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International Petroleum Corporation

Audited Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

International
Petroleum
Corp.

Consolidated Financial Statement
For the years ended December 31, 2021 and 2020, AUDITED

Contents

REPORT OF MANAGEMENT

The accompanying consolidated financial statements of International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") and other information contained in the management's discussion and analysis are the responsibility of management and have been approved by the Board of Directors. The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") as outlined in Part 1 of the Handbook of the Chartered Professional Accountants of Canada, and include some amounts that are based on management's estimates and judgment.

The Board of Directors carries out its responsibility for the consolidated financial statements principally through its Audit Committee, which is comprised solely of independent directors. The Audit Committee reviews the Group's annual consolidated financial statements and recommends its approval to the Board of Directors. The Corporation's auditors have full access to the Audit Committee, with and without management being present. These consolidated financial statements have been audited by PricewaterhouseCoopers SA, Chartered Professional Accountants, Licensed Public Accountants.

(Signed) Mike Nicholson
Director, President and Chief Executive Officer

(Signed) Christophe Nerguararian
Chief Financial Officer

Vancouver, Canada
February 8, 2022

Independent auditor's report

To the Shareholders of International Petroleum Corporation

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of International Petroleum Corporation and its subsidiaries (together, the Corporation) as at December 31, 2021 and 2020, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

What we have audited
The Corporation's consolidated financial statements comprise:

- the consolidated statements of operations for the years ended December 31, 2021 and 2020;
- the consolidated statement of comprehensive income for the years then ended;
- the consolidated balance sheet as at December 31, 2021 and 2020;
- the consolidated statements of cash flows for the years then ended;
- the consolidated statements of changes in equity for the years then ended; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2021. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

PricewaterhouseCoopers SA, avenue Giuseppe-Motta 50, case postale, CH-1211 Genève 2, Switzerland
Téléphone: +41 58 792 91 00, Téléfax: +41 58 792 91 10, www.pwc.ch

Key audit matters	How our audit addressed the key audit matters
The impact of oil and gas reserves on net property, plant and equipment (PP&E) for the Canada, Malaysia, and France segments *Refer to note 1 - Corporate information, note 2 - Critical accounting estimates and judgements, and note 8 – Oil and Gas Properties to the consolidated financial statements.* The Corporation has USD 953.5 million of net PP&E assets as at December 31, 2021. Depletion charges were USD 119.0 million for the year then ended. PP&E is depleted based on the year's production in relation to the estimated total proved and probable reserves in accordance with the unit of production method. At each balance sheet date or when there are facts and circumstances that suggest that the net book value of capitalized costs within each field area cost centre is higher than anticipated future net cash flow from oil and gas reserves attributable to the Corporation's interest in the related field areas, the Corporation performs an assessment as to whether there is an indication that an asset may be impaired. Management determined the recoverable amounts of PP&E based on the higher of fair value less costs of disposal and value in use using estimated future discounted net cash flows of proved and probable oil and gas reserves. The Corporation's estimates of proved and probable oil and gas reserves used in the calculations for impairment tests and accounting for depletion have been reviewed by Management's experts, specifically independent qualified reserves auditor. Significant assumptions developed by management used to determine the recoverable amount include the proved and probable oil and gas reserves, expected production volumes, future oil and gas prices, future development costs, future production costs and the discount rate. We determined that this is a key audit matter due to (i) the significant judgment made by management, including the use of management's experts, when developing the expected future cash flows to determine the recoverable amount and the proved and probable oil and gas reserves; and (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence relating to management's estimates.	Our approach to addressing the matter included the following procedures, among others: ● The work of management's experts was used in performing the procedures to evaluate the reasonableness of the proved and probable oil and gas reserves used to determine depletion charges and the recoverable amount of PP&E for the Canada, France and Malaysia segments. As a basis for using this work, management's experts' competence, capability and objectivity were evaluated, their work performed was understood and the appropriateness of their work as audit evidence was evaluated by considering the relevance and reasonableness of the assumptions, methods and findings. ● Tested how management determined the recoverable amount and depletion charges for the Canada, France and Malaysia segments, which included the following: ○ Evaluated the appropriateness of the methods used by management in making these estimates. ○ Tested the data used in determining these estimates. ○ Evaluated the reasonableness of significant assumptions used in developing the underlying estimates: ▪ Expected production volumes, future development costs and future production costs by considering the past performance of each segment, and whether these assumptions were consistent with evidence obtained in other areas of the audit. ▪ Future oil and gas prices by comparing those prices with other reputable third-party industry forecasts. ▪ The discount rate, by performing an independent sensitivity analysis. ○ Recalculated the unit of production rates used to calculate depletion charges for the Canada, France and Malaysia segments.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Corporations's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor’s responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation’s internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Corporation to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Luc Schulthess.

PricewaterhouseCoopers SA

Luc Schulthess

Tarik Bouchama

February 8, 2022

Consolidated Statement of Operations
For the years ended December 31, 2021 and 2020, AUDITED

USD Thousands	Note	2021	2020
Revenue	*3*	666,409	324,164
Cost of sales			
Production costs	*4*	(325,007)	(204,628)
Depletion and decommissioning costs	*8*	(119,013)	(111,896)
Depreciation of other tangible fixed assets	*10*	(10,108)	(11,681)
Exploration and business development costs		(1,960)	(6,802)
Impairment costs of oil and gas properties	*8*	–	(73,143)
Gross profit / (loss)	*3*	**210,321**	**(83,986)**
General, administration and depreciation expenses		(12,364)	(12,788)
Profit / (loss) before financial items		**197,957**	**(96,774)**
Finance income	*5*	285	13,103
Finance costs	*6*	(30,499)	(28,090)
Net financial items		**(30,214)**	**(14,987)**
Profit / (loss) before tax		**167,743**	**(111,761)**
Income tax recovery / (expense)	*7*	(21,684)	33,820
Net result		**146,059**	**(77,941)**
Net result attributable to:			
Shareholders of the Parent Company		146,028	(77,854)
Non-controlling interest		31	(87)
		146,059	**(77,941)**
Earnings per share – USD[1]	*17*	**0.94**	**(0.50)**
Earnings per share fully diluted – USD[1]	*17*	**0.92**	**(0.49)**

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

See accompanying notes to the consolidated financial statements

Consolidated Statement of Comprehensive Income
For the years ended December 31, 2021 and 2020, AUDITED

USD Thousands	Note	2021	2020
Net result		**146,059**	**(77,941)**
Other comprehensive income/(loss)			
Items that may be reclassified to profit or loss:			
Hedging (gains) / losses reclassified to profit or loss	*3*	33,592	1,983
Gains / (losses) on cash flow hedges		(31,253)	(3,098)
Income tax relating to these items		(562)	279
Currency translation adjustments		(5,409)	10,491
Items that will not be reclassified to profit or loss:			
Re-measurements on defined pension plan	*21*	578	(703)
Total comprehensive income / (loss)		**143,005**	**(68,989)**
Total comprehensive income/ (loss) attributable to:			
Shareholders of the Parent Company		142,980	(68,914)
Non-controlling interest		25	(75)
		143,005	**(68,989)**

See accompanying notes to the consolidated financial statements

Consolidated Balance Sheet
For the years ended December 31, 2021 and 2020, AUDITED

USD Thousands	Note	December 31, 2021	December 31, 2020
ASSETS			
Non-current assets			
Oil and gas properties	*8*	971,571	1,070,904
Other tangible fixed assets	*10*	46,363	59,198
Right-of-use assets	*11*	1,639	1,965
Deferred tax assets	*7*	67,188	88,347
Other assets	*12*	35,753	20,239
Total non-current assets		**1,122,514**	**1,240,653**
Current assets			
Inventories	*13*	20,195	17,070
Trade and other receivables	*14*	110,897	66,151
Derivative instruments	*23*	1,159	1,591
Current tax receivables		99	1,157
Cash and cash equivalents	*15*	18,810	6,498
Total current assets		**151,160**	**92,467**
TOTAL ASSETS		**1,273,674**	**1,333,120**
LIABILITIES			
Non-current liabilities			
Financial liabilities	*19*	109,219	301,153
Lease liabilities	*11*	980	1,347
Provisions	*20*	198,811	196,945
Deferred tax liabilities	*7*	22,142	28,085
Total non-current liabilities		**331,152**	**527,530**
Current liabilities			
Trade and other payables	*22*	79,841	63,350
Financial liabilities	*19*	1,806	22,982
Current tax liabilities		5,093	184
Lease liabilities	*11*	684	671
Provisions	*20*	7,555	7,204
Derivative instruments	*23*	–	2,746
Total current liabilities		**94,979**	**97,137**
EQUITY			
Shareholders' equity		847,386	708,321
Non-controlling interest		157	132
Net shareholders' equity		**847,543**	**708,453**
TOTAL EQUITY AND LIABILITIES		**1,273,674**	**1,333,120**

Approved by the Board of Directors

(Signed) C. Ashley Heppenstall
Director

(Signed) Mike Nicholson
Director

See accompanying notes to the consolidated financial statements

Consolidated Statement of Cash Flow
For the years ended December 31, 2021 and 2020, AUDITED

USD Thousands	Note	2021	2020
Cash flow from operating activities			
Net result		**146,059**	**(77,941)**
Adjustments for non-cash related items:			
Depletion, depreciation and amortization	*8, 10, 11*	130,837	125,280
Exploration costs	*8*	274	6,141
Impairment costs	*8*	–	73,143
Income tax	*7*	21,684	(33,820)
Capitalized financing fees	*6*	2,068	1,979
Foreign currency exchange	*5*	1,994	(13,028)
Interest expense	*6*	12,867	13,401
Unwinding of asset retirement obligation discount	*6*	11,488	10,837
Change in pension liability	*20*	293	603
Share-based costs	*18*	6,457	4,798
Other		255	1,205
Cash flow generated from operations (before working capital adjustments and income taxes)		**334,276**	**112,598**
Changes in working capital		(36,115)	(10,414)
Decommissioning costs paid	*20*	(3,945)	(4,324)
Other payments	*20*	(1,507)	(4,629)
Income taxes received / (paid)		425	(2,609)
Interest paid		(11,955)	(13,475)
Net cash flow from operating activities		**281,179**	**77,147**
Cash flow used in investing activities			
Investment in oil and gas properties	*8*	(43,990)	(77,659)
Investment in other fixed assets	*10*	(242)	(426)
Acquisition of Granite	*9*	–	(27,709)
Net cash (outflow) from investing activities		**(44,232)**	**(105,794)**
Cash flow from financing activities			
Borrowings / (Repayments)	*19*	(215,819)	41,549
Paid financing fees		(595)	(3,182)
Purchase of own shares	*16*	(7,293)	(17,602)
Other payments		(872)	(854)
Net cash (outflow) from financing activities		**(224,579)**	**19,911**
Change in cash and cash equivalents		**12,368**	**(8,736)**
Cash and cash equivalents at the beginning of the period		6,498	15,571
Currency exchange difference in cash and cash equivalents		(56)	(337)
Cash and cash equivalents at the end of the period		**18,810**	**6,498**

See accompanying notes to the consolidated financial statements

Consolidated Statement of Changes in Equity

For the years ended December 31, 2021 and 2020, AUDITED

USD Thousands	Share capital and premium	Retained earnings	CTA	IFRS 2 reserve	MTM reserve	Pension reserve	Total	Non-controlling interest	Total equity
Balance at January 1, 2020	549,311	230,038	6,052	6,249	3	(1,051)	790,602	207	790,809
Net result	–	(77,854)	–	–	–	–	(77,854)	(87)	(77,941)
Re-measurements on defined pension plan	–	–	–	–	–	(703)	(703)	–	(703)
Acquisition of Granite[1]	–	–	–	–	1,311	–	1,311	–	1,311
Cash flow hedge	–	–	–	–	(2,147)	–	(2,147)	–	(2,147)
Currency translation difference	–	–	10,724	274	(44)	(475)	10,479	12	10,491
Total comprehensive income	–	(77,854)	10,724	274	(880)	(1,178)	(68,914)	(75)	(68,989)
Purchase of own shares[2]	(17,602)	–	–	–	–	–	(17,602)	–	(17,602)
Share based payments	670	–	–	3,565	–	–	4,235	–	4,235
Balance at December 31, 2020	532,379	152,184	16,776	10,088	(877)	(2,229)	708,321	132	708,453

[1] *See Note 9*
[2] *See Note 16*

USD Thousands	Share capital and premium	Retained earnings	CTA	IFRS 2 reserve	MTM reserve	Pension reserve	Total	Non-controlling interest	Total equity
Balance at January 1, 2021	532,379	152,184	16,776	10,088	(877)	(2,229)	708,321	132	708,453
Net result	–	146,028	–	–	–	–	146,028	31	146,059
Re-measurements on defined pension plan	–	–	–	–	–	578	578	–	578
Cash flow hedge	–	–	–	–	1,777	–	1,777	–	1,777
Currency translation difference	–	–	(5,485)	(88)	(26)	196	(5,403)	(6)	(5,409)
Total comprehensive income	–	146,028	(5,485)	(88)	1,751	774	142,980	25	143,005
Purchase of own shares[1]	(7,221)	–	–	–	–	–	(7,221)	–	(7,221)
Share based payments	3,606	–	–	(300)	–	–	3,306	–	3,306
Balance at December 31, 2021	528,764	298,212	11,291	9,700	874	(1,455)	847,386	157	847,543

[1] *See Note 16*

See accompanying notes to the consolidated financial statements

1. CORPORATE INFORMATION

A. The Group

International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, 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 ("TSX") 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 2600, 595 Burrard Street, P.O. Box 49314, Vancouver, BC V7X 1L3, Canada and its business address is Suite 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

On April 10, 2021, IPC increased its working interest in the Bertam field, Malaysia, from 75% to 100% following the completion of the withdrawal of Petronas Carigali Sdn Bhd from Block PM307 and assignment of its working interest to IPC. An irrevocable notice of withdrawal was submitted by Petronas Carigali Sdn Bhd to IPC, as the operator of the Bertam field, in December 2020 following a review of its portfolio. The settlement for the transfer of the 25% additional working interest was the assumption by IPC of an additional USD 1,078 thousand of estimated future decommissioning liability, being the net difference of the estimated decommissioning liability associated with the working interest and the secured amounts transferred.

B. Basis of preparation

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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

These consolidated financial statements have been approved by the Board of Directors of IPC and authorized for issuance on February 8, 2022.

C. Going concern

The Group's consolidated financial statements for the year ended December 31, 2021, have been prepared on a going concern basis, which assumes that the Group will be able to realize its assets and discharge its liabilities in the normal course of business as they become due in the foreseeable future.

D. Changes in accounting policies and disclosures

During the year ended December 31, 2021, the Group applied the amended accounting standards, interpretations and annual improvement points that are effective as of January 1, 2021. The application of the amendments did not have a material impact on the consolidated financial statements.

There are no plans for the early adoption of published standards, interpretations, or amendments prior to their mandatory effective date. The Group does not expect that other changes in IFRS will have a material impact on the consolidated financial statements.

E. Basis of Consolidation

Subsidiaries
Subsidiaries are all entities over which the Group has control and are consolidated. The Corporation controls an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity.

The non-controlling interest in a subsidiary represents the portion of the subsidiary not owned by Group companies. The equity of the subsidiary relating to the non-controlling shareholders is shown as a separate item within changes in net equity.

Inter-company transactions, balances, income and expenses on transactions between companies are eliminated. Profits and losses resulting from intercompany transactions that are recognized in assets are also eliminated.

F. Joint Arrangements

Oil and gas operations of the Group are conducted as co-licencees in unincorporated joint ventures with other companies and are classified as joint operations. The consolidated financial statements reflect the relevant proportions of production, capital costs, operating costs and current assets and liabilities of the joint operation applicable to the Corporation's interests.

G. Foreign Currency Translation

Transactions and balances

Monetary assets and liabilities denominated in foreign currencies are translated at the rates of exchange prevailing at the balance sheet date and foreign exchange currency differences are recognized in the consolidated statement of operations. Transactions in foreign currencies are translated at exchange rates prevailing at the transaction date. Foreign exchange gains and losses are presented within finance income and costs in the consolidated statement of operations.

Functional and presentation currency

Items included in the financial statements of each of the operational entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The functional currency of the Corporation's operational entities are the USD, CAD, MYR and EUR. The consolidated financial statements are presented in USD which is the Corporation's presentation currency. The balance sheets and income statements of foreign companies are translated using the current rate method. All assets and liabilities are translated at the balance sheet date rates of exchange, whereas the income statements are translated at average rates of exchange for the year, except for transactions where it is more relevant to use the rate of the day of the transaction. The translation differences which arise are recorded directly in net assets.

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

	December 31, 2021		December 31, 2020	
	Average	Period end	Average	Period end
1 EUR equals USD	1.1835	1.1326	1.1413	1.2271
1 USD equals CAD	1.2536	1.2708	1.3412	1.2740
1 USD equals MYR	4.1433	4.1660	4.2026	4.0209

H. Classification of assets and liabilities

Non-current assets, long-term liabilities and provisions consist of amounts that are expected to be recovered or paid more than twelve months after the balance sheet date. Current assets and current liabilities consist solely of amounts that are expected to be recovered or paid within twelve months after the balance sheet date.

I. Oil and gas properties

Oil and gas properties are recorded at historical cost less depletion. All costs for acquiring concessions, licences or interests in production sharing contracts and for the survey, drilling and development of such interests are capitalized on a field area cost centre basis.

Costs directly associated with an exploration well are capitalized until the determination of reserves is evaluated. If it is determined that a commercial discovery has not been achieved, these exploration costs are charged to the income statement. During the exploration and development phases, no depletion is charged. The field will be transferred from the non-producing assets to the producing assets within oil and gas properties once production commences, and accounted for as a producing asset. Routine maintenance and repair costs for producing assets are expensed to the income statement when they occur.

Property, plant and equipment are depleted based on the year's production in relation to estimated total proved and probable reserves of oil and gas in accordance with the unit of production method. Depletion of a field area is charged to the income statement through cost of sales once production commences.

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and governmental regulations. Proved reserves can be categorized as developed or undeveloped. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimates.

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

Proceeds from the sale or farm-out of oil and gas concessions in the exploration stage are offset against the related capitalized costs of each cost centre with any excess of net proceeds over all costs capitalized included in the income statement. In the event of a sale in the exploration stage, any deficit is included in the income statement.

Impairment tests are performed annually or when there are indicators of impairment that suggest that the net book value of capitalized costs within each field area cost centre less any provision for asset retirement obligation costs, royalties and deferred production or revenue related taxes is higher than the anticipated future net cash flow from oil and gas reserves attributable to the Corporation's interest in the related field areas. Capitalized costs cannot be carried unless those costs can be supported by future cash flows from that asset. Provision is made for any impairment, where the net carrying value, according to the above, exceeds the recoverable amount, which is the higher of value in use and fair value less costs of disposal, determined through estimated future discounted net cash flows using prices and cost levels used by management in their internal forecasting. If there is a decision to not continue with a field specific exploration program, the costs will be expensed at the time the decision is made.

J. Other tangible fixed assets

Other tangible fixed assets are stated at cost less accumulated depreciation. The cost includes the original purchase price of the asset and the costs attributable to bringing the asset to its working condition for its intended use. Depreciation is based on cost and is calculated on a straight line basis over the estimated economic life of 3 to 5 years for office equipment and other assets. The Floating Production Storage and Offloading ("FPSO") located on the Bertam field, Malaysia, is being depreciated on a unit of production basis based on the Bertam field 2P reserves.

Additional costs to existing assets are included in the assets' net book value or recognized as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The net book value of any replaced parts is written off. Other additional expenses are deemed to be repair and maintenance costs and are charged to the income statement when they are incurred.

The net book value is written down immediately to its recoverable amount when the net book value is higher. The recoverable amount is the higher of an asset's fair value less cost of disposal and value in use. The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at the end of each reporting period.

K. Leases

The Group leases various offices, warehouses, equipment and cars. Rental contracts are typically made for fixed periods of 3 to 5 years but may have extension options. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

Right-of-use assets and corresponding liabilities are recognized when the leased asset is available for use by the Group. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to profit or loss over the period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. The right-of-use asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis.

Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the fixed and variable lease payments and the exercise price of the purchase option. The lease payments are discounted using the incremental borrowing rate and are classified as finance leases. The right-of-use assets are measured at cost comprising the amount of the initial measurement of the lease liability, any lease payments made and any initial direct costs.

Payments associated with short-term leases and leases of low-value assets are recognized on a straight-line basis as an expense in profit or loss.

L. Impairment of Assets

At each balance sheet date or when there are facts and circumstances that suggest that the net book value of capitalized costs within each field area cost center is higher than anticipated future net cash flow from oil and gas reserves attributable to the Corporation's interest in the related field areas, the Corporation performs an assessment as to whether there is an indication that an asset may be impaired. Management determined the recoverable amounts of property, plant and equipment based on the higher of fair value less costs of disposal and value in use using estimated future discounted net cash flows of proved and probable oil and gas reserves. The Corporation's estimates of proved and probable oil and gas reserves used in the calculations for impairment tests and accounting for depletion have been reviewed by Management's experts, specifically independent qualified reserves auditor.

The recoverable amount is the higher of fair value less costs of disposal and value in use. In determining fair value less costs of disposal, recent market transactions are considered, if available. In the absence of such transactions, an appropriate valuation model is used. Value in use is calculated by discounting estimated future cash flows to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. When the recoverable amount is less than the carrying value an impairment loss is recognized with the expensed charge to the income statement. If indications exist that previously recognized impairment losses no longer exist or are decreased, the recoverable amount is estimated. When a previously recognized impairment loss is reversed the carrying amount of the asset is increased to the estimated recoverable amount but the increased carrying amount may not exceed the carrying amount after depreciation that would have been determined had no impairment loss been recognized for the asset in prior years. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. An impairment loss is the amount by which the carrying amount of the individual asset or CGU exceeds its recoverable amount.

M. Financial Instruments

Financial assets and financial liabilities are recognized on the consolidated balance sheet on the trade date, the date on which the Group becomes a party to the contractual provisions of the financial instrument. All financial instruments are required to be classified and measured at fair value on initial recognition. Measurement in subsequent periods is dependent upon the classification of the financial instrument. The Group classifies its financial instruments in the following categories:

Financial Assets at Amortized Cost

Assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortized cost. The Group's loans and receivables consist of fixed or determined cash flows related solely to principal and interest amounts or contractual sales of oil. The Group's intent is to hold these receivables until cash flows are collected. Loans and receivables are recognized initially at fair value, net of any transaction costs incurred and subsequently measured at amortized cost.

Financial Assets at Fair Value through Profit or Loss ("FVTPL")

Financial assets measured at FVTPL are assets which do not qualify as financial assets at amortized cost or at fair value through other comprehensive income.

Financial Liabilities at Amortized Cost

Financial liabilities are measured at amortized cost, unless they are required to be measured at FVTPL, or the Group has opted to measure them at FVTPL. Borrowings and accounts payable are recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial Liabilities at FVTPL

Financial liabilities measured at FVTPL are liabilities which include embedded derivatives and cannot be classified as amortized cost.

Impairment of Financial Assets

The measurement of impairment of financial assets is based on the expected credit losses model. For the trade and other receivables, the Group applies the simplified approach which requires the use of the lifetime expected loss provision for all trade receivables. In estimating the lifetime expected loss provision, the Group considered historical industry default rates as well as credit ratings of major customers. Additional disclosure related to the Group's financial assets is included in Note 23.

N. Derivative Financial Instruments and Hedging Activities

Derivatives are initially recognized at fair value on the date a derivative contract is entered into and are subsequently remeasured to their fair value. The method of recognizing the resulting gain or loss depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged. The Group designates certain derivatives as either hedges of a particular risk associated with a recognized asset or liability or a highly probable forecasted transaction, hedges of the fair value of recognized assets and liabilities or a firm commitment, or hedges of a net investment in a foreign operation.

The Group documents at the inception of the transaction the relationship between hedging instruments and the hedged items, as well as its risk management objectives and strategy for undertaking various hedging transactions. The Group also documents its assessment, both at hedge inception and on an ongoing basis, of whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of the hedged items. The fair values of various derivative financial instruments used for hedging purposes are disclosed in Note 23. Movements on the hedging reserve is reflected in other comprehensive income. The full fair value of a hedging derivative is classified as a non-current asset or liability when the remaining maturity of the hedged item is more than twelve months and as a current asset or liability when the remaining maturity of the hedged item is less than twelve months.

Cash flow hedge

The effective portion of changes in the fair value of derivatives that are designated and qualify as cash flow hedges is recognized in other comprehensive income. The gain or loss relating to the ineffective portion, if any, is recognized immediately within finance income or costs. Amounts accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss. When a hedging instrument expires or is sold, or when a hedge no longer meets the criteria for hedge accounting, any cumulative gain or loss existing in equity at that time remains in equity and is recognized when the forecast transaction is ultimately recognized in the profit or loss. When a forecasted transaction is no longer expected to occur, the cumulative gain or loss that was reported in equity is immediately recognized in profit or loss as finance income or costs.

O. Inventories

Inventories of consumable well supplies are stated at the lower of cost and net realizable value, cost being determined on a weighted average cost basis. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses. Inventories of hydrocarbons are stated at the lower of cost and net realizable value. Under or overlifted positions of hydrocarbons are valued at market prices prevailing at the balance sheet date. An underlift of production from a field is included in the current receivables and valued at the reporting date spot price or prevailing contract price and an overlift of production from a field is included in the current liabilities and valued at the reporting date spot price or prevailing contract price. A change in the over or underlift position is reflected in the income statement as revenue.

P. Cash and cash equivalents

Cash and cash equivalents include cash at bank and cash in hand.

Q. Provisions

A provision is reported when the Group has a legal or constructive obligation as a consequence of a past event and when it is more likely than not that an outflow of resources is required to settle the obligation and a reliable estimate can be made of the amount.

Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognized as financial expense.

On fields where there is an obligation to contribute to asset retirement obligation costs, a provision is recorded to recognize the future commitment. An asset is created, as part of the oil and gas property, to represent the discounted value of the anticipated asset retirement obligation liability and depleted over the life of the field on a unit of production basis. The corresponding accounting entry to the creation of the asset recognizes the discounted value of the future liability. The discount applied to the anticipated asset retirement obligation liability is subsequently released over the life of the field and is charged to financial expenses. Changes in asset retirement obligation costs and reserves are treated prospectively and consistent with the treatment applied upon initial recognition.

R. Revenue and Other Operating Revenue

Revenue associated with the sale of crude oil and natural gas is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Group recognizes revenue when it transfers control of the product or service to a customer, which is generally when title passes from the Group to its customer. The Group satisfies its performance obligations in contracts with customers upon the delivery of crude oil and natural gas, which is generally at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

Royalties payments to governments and other mineral interest owners are recognized as a cost in the revenue section.

Production and sales taxes directly attributable to fields, including export duties, are expensed in the income statement and classified as direct production taxes included within production costs. Production taxes payable in cash are accrued in the accounting period in which the liability arises.

Prior to April 2021, the Group recognized revenue from the FPSO in other operating revenue as earned from third party participants in the Bertam field, Malaysia. Other operating revenue also includes pipeline tariffs earned.

S. Employee Benefits

Short-term employee benefits
Short-term employee benefits such as salaries, social premiums and holiday pay, are expensed when incurred.

Pension obligations
The pension obligations consist of defined contribution plans for all companies within the Group except for one Swiss subsidiary, International Petroleum SA. A defined contribution plan is a pension plan under which the Group pays fixed contributions. The Group has no further payment obligations once the contributions have been paid. The contributions are recognized as an expense when they are due.

International Petroleum SA has a defined benefit pension plan that is managed through a private pension plan. Independent actuaries determine the cost of the defined benefit plan on an annual basis, and the subsidiary pays the annual insurance premium. The pension plan provides benefits coverage to the employees of International Petroleum SA in the event of retirement, death or disability. International Petroleum SA and its employees jointly finance retirement and risk benefits. Employees of International Petroleum SA pay 40% of the savings contributions, of the risk contributions and of the cost contributions and International Petroleum SA contributes the difference between the total of all required pension plan contributions and the total of all employees' contributions.

Share-based payments

The Group operates an equity-settled, share-based compensation plan under which the entity receives services from employees, directors and officers as consideration for equity instruments of the Corporation. Equity-settled share-based payments are recognized in the income statement as expenses during the vesting period and as equity in the balance sheet. The option is measured at fair value at the date of the grant using an appropriate options pricing model and is charged to the income statement over the vesting period without revaluation of the value of the option.

T. Taxation

The components of tax are current and deferred. Tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case it is accounted for consistently with the related item.

Current tax is tax that is to be paid or received for the year in question and also includes adjustments of current tax attributable to previous periods.

Deferred income tax is a non-cash charge provided, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying values. Temporary differences can occur for example where investment expenditure is capitalized for accounting purposes but the tax deduction is accelerated or where asset retirement obligation costs are provided for in the financial statements but not deductible for tax purposes until they are actually incurred. However, the deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit nor loss.

Deferred income tax is provided on temporary differences arising on investments in subsidiaries and associates, except where the timing of the reversal of the temporary difference is controlled by the Corporation and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred income tax asset is realized or the deferred income tax liability is settled. Deferred income tax assets are recognized to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized.

Deferred tax assets are offset against deferred tax liabilities in the balance sheet where they relate to the same jurisdiction and there is a legally enforceable right to offset.

U. Segment Reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker, which, due to the unique nature of each country's operations, commercial terms or fiscal environment, is at a country level.

V. Business combinations

Acquisitions of businesses are accounted for using the purchase method of accounting whereby all identifiable assets and liabilities are recorded at their fair values as at the date of acquisition. Any excess purchase price over the aggregate fair value of net assets is recorded as goodwill. Goodwill is identified and allocated to cash-generating units ("CGU"), or groups of CGUs, that are expected to benefit from the synergies of the acquisition. Goodwill is not amortized. Any excess of the aggregate fair value of net assets over the purchase price is recognized in the consolidated statement of operations.

A CGU to which goodwill has been allocated is tested for impairment at least annually or when events or circumstances indicate that an assessment for impairment is required. For goodwill arising on an acquisition in a financial year, the CGU to which the goodwill has been allocated is tested for impairment before the end of that financial year.

When the recoverable amount of the CGU is less than the carrying amount of that CGU, the impairment loss is allocated to reduce the carrying amount of any goodwill allocated to that CGU first, and then to the other assets of that CGU pro rata on the basis of the carrying amount of each asset in the CGU. Any impairment loss for goodwill is recognized directly in the consolidated statement of earnings. An impairment loss for goodwill is not reversed in subsequent periods.

On disposal of a subsidiary, the attributable amount of goodwill is included in the determination of the gain or loss on disposal.

2. CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

In connection with the preparation of the consolidated financial statements, the Group's 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. The assumptions, estimates and judgments are based on historical experience, current trends and other factors that management believes to be relevant at the time the consolidated financial statements are prepared. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that the consolidated 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:

Estimates in oil and gas reserves

Estimates of oil and gas reserves are used in the calculations for impairment tests and accounting for depletion and asset retirement obligation. Standard recognized evaluation techniques are used to estimate the proved and probable reserves. These techniques take into account the future level of development required to produce the reserves. An independent qualified reserves auditor reviews these estimates. Changes in estimates in oil and gas reserves, resulting in different future production profiles, will affect the discounted cash flows used in impairment testing, the anticipated date of site decommissioning and restoration and the depletion charges in accordance with the unit of production method. Changes in estimates in oil and gas reserves could for example result from additional drilling, observation of long-term reservoir performance or changes in economic factors such as oil price and inflation rates.

Impairment of oil and gas properties

Key assumptions in the impairment models relate to prices and costs that are based on forward curves and the long-term corporate assumptions. Annual impairment tests are performed in conjunction with the annual reserves certification process. The impairment test requires the use of estimates. For the purpose of determining a potential impairment, the significant assumptions developed by management used to determine the recoverable amount include the proved and probable oil and gas reserves, expected production volumes, future oil and gas prices, future development costs, future production costs and the discount rate. These assumptions and judgements of management that are based on them are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates and the discount rate applied is reviewed throughout the year.

Provision for asset retirement obligations

Amounts used in recording a provision for asset retirement obligations are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and decommissioning. Due to changes in relation to these items, the future actual cash outflows in relation to the site decommissioning and restoration can be different. To reflect the effects due to changes in legislation, requirements and technology and price levels, the carrying amounts of asset retirement obligation 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 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.

Fair value of assets acquired and liabilities assumed in a business combination

The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and any goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward commodity prices, reserves and resources estimates, production costs and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

3. SEGMENT INFORMATION

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

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

	2021				
USD Thousands	Canada	Malaysia	France	Other	Total
Crude oil	458,690	100,436	75,949	–	**635,075**
NGLs	570	–	–	–	**570**
Gas	100,019	–	–	–	**100,019**
Net sales of oil and gas	**559,279**	**100,436**	**75,949**	–	735,664
Change in under/over lift position	–	–	5,391	–	**5,391**
Royalties	(46,424)	–	–	–	**(46,424)**
Hedging settlement	(33,592)	–	–	–	**(33,592)**
Other operating revenue	171	4,208	927	64	**5,370**
Revenue	**479,434**	**104,644**	**82,267**	**64**	666,409
Production costs	(259,716)	(25,243)	(40,048)	–	**(325,007)**
Depletion and decommissioning costs	(72,764)	(30,156)	(16,093)	–	**(119,013)**
Depreciation of other tangible fixed assets	–	(10,108)	–	–	**(10,108)**
Exploration and business development costs	(8)	(259)	(7)	(1,686)	**(1,960)**
Gross profit/(loss)	**146,946**	**38,878**	**26,119**	**(1,622)**	210,321

	2020				
USD Thousands	Canada	Malaysia	France	Other	Total
Crude oil	167,352	60,465	35,700	–	**263,517**
NGLs	214	–	–	–	**214**
Gas	59,950	–	–	–	**59,950**
Net sales of oil and gas	**227,516**	**60,465**	**35,700**	–	323,681
Change in under/over lift position	–	–	(630)	–	**(630)**
Royalties	(14,064)	–	–	–	**(14,064)**
Hedging settlement	(1,983)	–	–	–	**(1,983)**
Other operating revenue	–	15,555	1,164	441	**17,160**
Revenue	**211,469**	**76,020**	**36,234**	**441**	324,164
Production costs	(153,382)	(24,793)	(26,453)	–	**(204,628)**
Depletion and decommissioning costs	(66,810)	(27,759)	(17,327)	–	**(111,896)**
Depreciation of other tangible fixed assets	–	(11,681)	–	–	**(11,681)**
Exploration and business development costs	(3,011)	(741)	(2,389)	(661)	**(6,802)**
Impairment costs of oil and gas properties	–	–	(73,143)	–	**(73,143)**
Gross profit/(loss)	**(11,734)**	**11,046**	**(83,078)**	**(220)**	(83,986)

	Assets		Liabilities	
USD Thousands	2021	2020	2021	2020
Malaysia	342,636	308,044	200,519	215,688
France	175,479	167,916	106,346	152,645
Canada	1,135,017	1,197,240	695,051	868,253
Corporate	92,899	164,574	40,550	38,201
Other	128,331	126,227	(15,647)	(19,239)
Intercompany balance elimination	(600,688)	(630,881)	(600,688)	(630,881)
Total Assets / Liabilities	**1,273,674**	**1,333,120**	**426,131**	**624,667**
Shareholders' equity	N/A	N/A	847,386	708,321
Non-controlling interest	N/A	N/A	157	132
Total equity for the group	N/A	N/A	**847,543**	**708,453**
Total consolidated	**1,273,674**	**1,333,120**	**1,273,674**	**1,333,120**

4. PRODUCTION COSTS

USD Thousands	2021	2020
Cost of operations	203,537	154,411
Tariff and transportation expenses	33,879	21,875
Direct production taxes	10,813	7,510
Operating costs	**248,229**	**183,796**
Cost of blending[1]	78,434	20,691
Change in inventory position	(1,656)	141
Total production costs	**325,007**	**204,628**

[1] *In Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. Cost of blending represents the contracted purchase of diluent used for blending net of proceeds from the sale of surplus diluent. A net gain of USD 421 thousand and a cost of USD 1,258 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for the year ended December 31, 2021* and December 31, 2020 respectively.

5. FINANCE INCOME

USD Thousands	2021	2020
Foreign exchange gain, net	–	13,028
Interest income	254	75
Other financial income	31	–
Total finance income	**285**	**13,103**

6. FINANCE COSTS

USD Thousands	2021	2020
Foreign exchange loss, net	1,994	–
Interest expense	12,867	13,401
Unwinding of asset retirement obligation discount	11,488	10,837
Amortization of loan fees	2,068	1,979
Loan commitment fees	1,666	1,204
Other financial costs	416	669
Total finance costs	**30,499**	**28,090**

7. INCOME TAX RECOVERY / (EXPENSE)

USD Thousands	2021	2020
Current tax	(4,670)	(113)
Deferred tax	(17,014)	33,933
Total tax recovery / (expense)	**(21,684)**	**33,820**

The deferred tax amount arises primarily where there is a difference in depletion for tax and accounting purposes. The deferred tax debit in the statement of operations for the current period mainly relates to the tax profit incured and the tax losses used during the year 2021.

The tax on the Group's profit before tax differs from the theoretical amount that would arise using the tax rate of Canada as follows:

USD Thousands	2021	2020
Profit before tax	167,743	(111,761)
Tax calculated at the corporate tax rate in Canada 25%	(41,936)	27,940
Effect of foreign and domestic tax rates	2,835	8,540
Tax effect of statutory rate change	904	3,939
Tax effect of (recognition) / derecognition of unrecorded tax losses	12,614	(9,230)
Tax effect due to true-up of provision to prior year tax filings	1,324	1,852
Other	2,575	779
Total tax	**(21,684)**	**33,820**

Specification of deferred tax assets and tax liabilities[1]

USD Thousands	2021	2020
Unused tax loss carry forward	115,560	133,753
Other	3,414	2,841
Deferred tax assets	**118,974**	**136,594**
Accelerated allowances	73,641	76,014
Other	287	318
Deferred tax liabilities	**73,928**	**76,332**
Deferred taxes, net	**45,046**	**60,262**

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

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

Deferred tax assets in relation to tax loss carried forwards are only recognized in so far that there is a reasonable certainty as to the timing and the extent of their realization. The recognized unused tax loss carry forward mainly relates to Canada. The Group has concluded that the deferred assets will be recoverable using the estimated future taxable income based on the approved business plans and budgets.

8. OIL AND GAS PROPERTIES

USD Thousands	2021	2020
Exploration and Evaluation Assets	18,037	20,986
Property, plant and Equipment	953,534	1,049,918
Oil and Gas Properties	**971,571**	**1,070,904**

Exploration and Evaluation Assets

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2021	15,409	44	5,533	20,986
Additions[1]	(2,723)	472	7	(2,244)
Expensed exploration and evaluation costs	(8)	(259)	(7)	(274)
Reclassification	–	(76)	–	(76)
Currency translation adjustments	73	–	(428)	(355)
Net book value December 31, 2021	**12,751**	**181**	**5,105**	**18,037**

[1] *Net revenues on appraisal projects are being offset against capitalised costs of Exploration and Evaluation assets.*

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2020	13,899	6,761	6,954	27,614
Additions	4,264	460	522	5,246
Expensed exploration and evaluation costs	(3,011)	(741)	(2,389)	(6,141)
Reclassification[1]	(84)	(6,436)	(51)	(6,571)
Currency translation adjustments	341	–	497	838
Net book value December 31, 2020	**15,409**	**44**	**5,533**	**20,986**

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

Property, Plant and Equipment

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2021	1,004,605	523,728	437,660	1,965,993
Additional working interest[1]	–	1,078	–	1,078
Additions	33,450	10,333	2,451	46,234
Change in estimates	(18,174)	(772)	1,594	(17,352)
Reclassification	–	76	–	76
Currency translation adjustments	2,063	–	(33,494)	(31,431)
December 31, 2021	**1,021,944**	**534,443**	**408,211**	**1,964,598**
Accumulated depletion				
January 1, 2021	(195,322)	(420,191)	(300,562)	(916,075)
Depletion charge for the period	(72,764)	(30,156)	(16,093)	(119,013)
Currency translation adjustments	501	–	23,523	24,024
December 31, 2021	**(267,585)**	**(450,347)**	**(293,132)**	**(1,011,064)**
Net book value December 31, 2021	**754,359**	**84,096**	**115,079**	**953,534**

[1] *Relates to the increased decommissioning liability relating to the additional 25% working interest in the Bertam field, Malaysia. (Also see Note 1).*

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2020	905,394	493,231	385,775	1,784,400
Granite Acquisition (see Note 9)	47,076	–	–	47,076
Additions	40,816	20,274	11,323	72,413
Change in estimates	(11,395)	3,787	4,423	(3,185)
Reclassification	84	6,436	51	6,571
Currency translation adjustments	22,630	–	36,088	58,718
December 31, 2020	**1,004,605**	**523,728**	**437,660**	**1,965,993**
Accumulated depletion				
January 1, 2020	(122,595)	(392,432)	(191,492)	(706,519)
Depletion charge for the period	(66,810)	(27,759)	(17,327)	(111,896)
Impairment costs of oil and gas properties	–	–	(73,143)	(73,143)
Currency translation adjustments	(5,917)	–	(18,600)	(24,517)
December 31, 2020	**(195,322)**	**(420,191)**	**(300,562)**	**(916,075)**
Net book value December 31, 2020	**809,283**	**103,537**	**137,098**	**1,049,918**

Impairment test
The Group carried out its impairment testing at December 31, 2021, on a CGU basis in conjunction with the annual reserves audit process. The Group used appropriate oil or natural gas price curves based on forward forecasts as at December 31, 2021, a future cost inflation factor of 2% (2020: 2%) per annum, production and cost profiles based on proved and probable reserves (2P reserves) as at December 31, 2021 and a discount rate of 8.5% (8.5% at December 31, 2020) to calculate the estimated future post-tax cash flows.

The following prices were used in the impairment testing as at December 31, 2021:

Price Decks	2022	2023	2024	2025	2026	Average annual increase thereafter
Dated Brent (USD/bbl)	75.00	72.00	70.00	71.40	72.83	2%
West Texas Intermediate (USD/bbl)	73.00	70.00	68.00	69.36	70.75	2%
Western Canadian Select (USD/bbl)	60.50	57.25	55.00	56.09	57.22	2%
Empress Gas (CAD/MMbtu)	4.55	3.92	3.59	3.67	3.74	2%

In 2021, as a result of the testing, no impairment of the oil and gas properties was required.

Sensitivities were calculated on the valuation of the estimated future post-tax cash flows. Using a discount rate of 10% instead of 8.5% or a USD 2/bbl decrease in the oil price curve or using a flat gas price curve at CAD 3.00/mcf did not result in an impairment charge.

9. GRANITE ACQUISITION

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

The Granite Acquisition has been accounted for as a business combination with IPC being the acquirer, and in accordance with IFRS 3 Business Combinations, the assets acquired and liabilities assumed have been recorded at their fair values.

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

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

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

The Corporation performed a preliminary purchase price allocation for the acquisition. The amounts disclosed above were determined provisionally pending the finalization of the valuation for those assets and liabilities. Up to twelve months from the effective date of the Granite Acquisition, further adjustments may be made to the fair values assigned to the identifiable assets acquired and liabilities assumed. No such further adjustments are expected.

Acquisition-related costs of approximately USD 0.5 million have been recognized in the statement of operations during the year ended December 31, 2020. No further costs have been incurred during the year ended December 31, 2021.

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

10. OTHER TANGIBLE FIXED ASSETS

USD Thousands	FPSO	Other	Total
Cost			
January 1, 2021	208,063	10,413	218,476
Additions	–	242	242
Disposals	–	(72)	(72)
Currency translation adjustments	(1,890)	(420)	(2,310)
December 31, 2021	**206,173**	**10,163**	**216,336**
Accumulated depreciation			
January 1, 2021	(152,416)	(6,862)	(159,278)
Depreciation charge for the period	(10,108)	(979)	(11,087)
Disposals	–	72	72
Currency translation adjustments	–	320	320
December 31, 2021	**(162,524)**	**(7,449)**	**(169,973)**
Net book value December 31, 2021	**43,649**	**2,714**	**46,363**

USD Thousands	FPSO	Other	Total
Cost			
January 1, 2020	205,989	9,420	215,409
Granite Acquisition (see Note 9)	–	85	85
Additions	–	426	426
Disposals	–	(79)	(79)
Currency translation adjustments	2,074	561	2,635
December 31, 2020	**208,063**	**10,413**	**218,476**
Accumulated depreciation			
January 1, 2020	(140,735)	(5,659)	(146,394)
Depreciation charge for the period	(11,681)	(882)	(12,563)
Disposals	–	79	79
Currency translation adjustments	–	(400)	(400)
December 31, 2020	**(152,416)**	**(6,862)**	**(159,278)**
Net book value December 31, 2020	**55,647**	**3,551**	**59,198**

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

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

11. RIGHT-OF-USE ASSETS AND LEASE LIABILITIES

USD Thousands	Buildings
January 1, 2021	1,965
Additions	434
Depreciation	(737)
Currency translation adjustments	(23)
Right-of-use-assets as at December 31, 2021	**1,639**
Current	684
Non-Current	980
Lease Liabilities as at December 31, 2021	**1,664**

USD Thousands	Buildings
January 1, 2020	2,700
Additions	60
Depreciation	(821)
Currency translation adjustments	26
Right-of-use assets as at December 31, 2020	**1,965**
Current	671
Non-Current	1,347
Lease Liabilities as at December 31, 2020	**2,018**

12. OTHER ASSETS

USD Thousands	December 31, 2021	December 31, 2020
Long-term receivables	28,024	20,210
Financial assets	7,729	29
	35,753	**20,239**

Long-term receivables represent cash payments made to an asset retirement obligation fund and financial assets mainly represent secured amounts transferred for the future asset retirement obligation, in respect of the Bertam field, Malaysia. The increase in long-term receivables and financial assets have been transferred to the Group following the assignment of the additional 25% working interest of the Bertam field. (Also see Notes 1 and 20).

13. INVENTORIES

USD Thousands	December 31, 2021	December 31, 2020
Hydrocarbon stocks	8,355	6,606
Well supplies and operational spares	11,840	10,464
	20,195	**17,070**

14. TRADE AND OTHER RECEIVABLES

USD Thousands	December 31, 2021	December 31, 2020
Trade receivables	91,062	51,614
Underlift	9,827	5,057
Joint operations debtors	1,930	1,792
Prepaid expenses and accrued income	6,325	5,524
Other	1,753	2,164
	110,897	**66,151**

15. CASH AND CASH EQUIVALENTS

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

16. SHARE CAPITAL

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

	Number of shares
Balance at January 1, 2020	**159,790,869**
Cancellation of repurchased common shares	(4,448,112)
Balance at December 31, 2020	**155,342,757**
Stock option exercise	25,000
Cancellation of repurchased common shares	(169,652)
Balance at December 31, 2021	**155,198,105**

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

As at January 1, 2020, the total number of common shares issued and outstanding in IPC was 159,790,869. During Q1 2020, IPC repurchased an aggregate of 4,448,112 common shares under a share repurchase program and all of these shares were cancelled. As at December 31, 2020, IPC had a total of 155,342,757 common shares issued and outstanding.

Following the exercise of stock options during February 2021, the number of issued and outstanding common shares of the Corporation increased by 25,000 to 155,367,757 common shares with voting rights.

On December 1, 2021, IPC announced the commencement of a share repurchase program. During the period up to December 31, 2021, IPC repurchased an aggregate of 1,330,303 common shares of which 169,652 shares were cancelled prior to December 31, 2021. The remaining 1,160,651 shares were cancelled in January 2022. As at December 31, 2021, IPC had a total of 155,198,105 common shares issued and outstanding.

As at February 8, 2022, following the cancellation of a further 726,676 common shares repurchased, IPC has a total of 153,310,778 common shares issued and outstanding with no par value.

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

17. EARNINGS PER SHARE

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

USD Thousands	2021	2020
Net result attributable to shareholders of the Parent Company, USD	146,028,617	(77,854,090)
Weighted average number of shares for the period	155,363,445	156,439,552
Earnings per share, USD	**0.94**	**(0.50)**
Weighted average diluted number of shares for the period	158,432,436	158,427,821
Earnings per share fully diluted, USD	**0.92**	**(0.49)**

18. SHARE BASED PAYMENTS

The Group has the following equity-settled share-based compensation plans: (a) a Share Unit Plan and (b) a Stock Option Plan.

IPC Share Unit Plan
The shareholders of IPC at the 2018 Annual General Meeting and at the 2021 Annual General Meeting approved a Share Unit Plan. Awards under the plan will be accounted from the date of grant.

The IPC Performance Share Plan ("PSP") 2018 awards vested on June 30, 2021 at a price of CAD 5.77 per award.

The IPC PSP 2019 awards are subject to continued employment and to certain performance conditions being met. The total outstanding number of awards at December 31, 2021, is 860,349 which vest on June 30, 2022. Each award was fair valued at the grant date at CAD 4.28 using an adjusted share price calculated with a hybrid valuation model based on the Monte Carlo simulation. The assumptions used in the calculation of the adjusted share price were a risk free rate of 2.00%, expected volatility of 46%, dividend yield rate of 0%, and an exercise price of CAD zero.

The IPC PSP 2020 awards are subject to continued employment and to certain performance conditions being met. The total outstanding number of awards at December 31, 2021, is 1,017,105 which vest on March 1, 2023. Each award was fair valued at the grant date at CAD 3.65 using an adjusted share price calculated with a hybrid valuation model based on the Monte Carlo simulation. The assumptions used in the calculation of the adjusted share price were a risk free rate of 2.00%, expected volatility of 47%, dividend yield rate of 0%, and an exercise price of CAD zero.

The IPC PSP 2021 awards are subject to continued employment and to certain performance conditions being met. The total outstanding number of awards at December 31, 2021, is 1,716,000 which vest on March 1, 2024. Each award was fair valued at the grant date at CAD 3.61 using an adjusted share price calculated with a hybrid valuation model based on the Monte Carlo simulation. The assumptions used in the calculation of the adjusted share price were a risk free rate of 2.00%, expected volatility of 68%, dividend yield rate of 0%, and an exercise price of CAD zero.

IPC Performance Share Plan	2018 Awards	2019 Awards	2020 Awards	2021 Awards	Total
Outstanding at January 1, 2021	501,500	902,933	1,086,000	–	2,490,433
Awarded during the period	–	–	–	1,716,000	1,716,000
Forfeited during the period	–	(42,584)	(68,895)	–	(111,479)
Vested during the period	(501,500)	–	–	–	(501,500)
Outstanding at December 31, 2021	–	**860,349**	**1,017,105**	**1,716,000**	**3,593,454**
Vesting date					
June 30, 2022	–	860,349	–	–	860,349
March 1, 2023	–	–	1,017,105	–	1,017,105
March 1, 2024	–	–	–	1,716,000	1,716,000
Outstanding at December 31, 2021	–	**860,349**	**1,017,105**	**1,716,000**	**3,593,454**

The last third of the IPC Restricted Share Plan ("RSP") 2018 awards vested on June 30, 2021, at a price of CAD 5.77 per award.

The second third of the IPC RSP 2019 awards vested on June 30, 2021, at a price of CAD 5.77 per award. The total outstanding number of 2019 awards under the IPC RSP as at December 31, 2021, is 132,142 which vest on June 30, 2022, subject to continued employment. Each award was fair valued at the grant date at CAD 5.84.

The first third of the IPC RSP 2020 awards vested on March 1, 2021, at a price of CAD 4.18 per award. The total outstanding number of 2020 awards under the IPC RSP as at December 31, 2021, is 404,410 which vest over two years on each of March 1, 2022 and March 1, 2023, subject to continued employment. Each award was fair valued at the grant date at CAD 4.35.

The total outstanding number of IPC RSP 2021 awards as at December 31, 2021, is 1,036,773 which vest over three years as to one-third on each of March 1, 2022, March 1, 2023, and March 1, 2024, subject to continued employment. Each award was fair valued at the grant date at CAD 4.07.

IPC Restricted Share Plan	2018 Awards	2019 Awards	2020 Awards	2021 Awards	Total
Outstanding at January 1, 2021	65,152	287,393	646,446	–	998,991
Awarded during the period	–	–	–	1,091,129	1,091,129
Forfeited during the period	–	(14,677)	(26,554)	(54,356)	(95,587)
Vested during the period	(65,152)	(140,574)	(215,482)	–	(421,208)
Outstanding at December 31, 2021	–	**132,142**	**404,410**	**1,036,773**	**1,573,325**
Vesting date					
June 30, 2022	–	132,142	–	–	132,142
March 1, 2022	–	–	202,205	345,591	547,796
March 1, 2023	–	–	202,205	345,591	547,796
March 1, 2024	–	–	–	345,591	345,591
Outstanding at December 31, 2021	–	**132,142**	**404,410**	**1,036,773**	**1,573,325**

In connection with the BlackPearl Acquisition, the Group granted awards under the IPC RSP for certain officers and employees. The second third vested on December 31, 2020, at a price of CAD 2.85 per award. The last third vested on December 31, 2021 at a price of CAD 6.94. Each award was fair valued at the grant date at CAD 4.35.

IPC Restricted Share Plan - BlackPearl	2019 RSP
Outstanding at January 1, 2021	91,777
Awarded during the period	–
Forfeited during the period	(10,769)
Vested during the period	(81,208)
Outstanding at December 31, 2021	–

Under the IPC Share Unit Plan, the Group allows non-employee directors of the Corporation to elect for awards for fees for services performed as a director and otherwise payable in cash. These awards will vest immediately at the time of grant. However, these awards may not be redeemed before the end of service as a director of the Corporation. The total outstanding RSP awards outstanding as at December 31, 2021, is 112,529. In 2019 there were 25,349 awards issued with a fair value at the grant date at CAD 5.76. In 2020 there were 25,335 awards issued with a fair value at the grant date at CAD 2.56 and 45,781 awards issued with a fair value at the grant date at CAD 2.85. In 2021 there were 18,167 awards issued with a fair value at the grant date at CAD 5.75 and 12,543 awards issued with a fair value at the grant date at CAD 6.95. In 2021, 14,646 awards issued in 2019 have been exercised at a price of CAD 6.44.

Stock Option Plan
The Stock Option Plan provides for the grant of stock option awards to employees, consultants and directors up to a maximum of 1,000,000 common shares of IPC. The Board granted stock options under the Stock Option Plan in February 2017, with a three year vesting period and a four year term. In February 2021, 25,000 stock options were exercised at CAD 4.77 and all remaining stock options expired. There are currently no outstanding stock options under the Stock Option Plan.

The number of awards outstanding under the Stock Option Plan at December 31, 2021, are summarized in the table below.

IPC Stock Option Plan	2021
Outstanding at January 1, 2021	1,808,566
Awarded during the period	–
Forfeited during the period	(1,783,566)
Exercised during the period	(25,000)
Outstanding at December 31, 2021	–

The costs charged to the statement of operations of the Group for the Share-Based payments are summarized in the following table:

USD Thousands	2021	2020
IPC Stock Option Plan	–	44
IPC PSP – 2018 Awards	337	682
IPC RSP – 2018 Awards	81	224
IPC PSP – 2019 Awards	397	987
IPC RSP – 2019 Awards	984	983
IPC PSP – 2020 Awards	643	822
IPC RSP – 2020 Awards	984	1,056
IPC PSP – 2021 Awards	1,599	–
IPC RSP – 2021 Awards	1,432	–
	6,457	**4,798**

19. FINANCIAL LIABILITIES

USD Thousands	December 31, 2021	December 31, 2020
Bank loans	113,121	327,691
Capitalized financing fees	(2,096)	(3,556)
	111,025	**324,135**

As at January 1, 2020, the Group had a reserve-based lending credit facility of USD 175 million (the "International RBL") with a maturity to end of June 2022 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had a reserve-based lending credit facility of CAD 375 million (the "Canadian RBL") with a maturity date in May 2021, in connection with its oil and gas assets in Canada.

In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France (the "France Facility") under a financial assistance program instituted by the French government. In April 2021, IPC extended the France Facility until May 2026, with quarterly repayments commencing in August 2022. The France Facility amount was fully drawn as at December 31, 2021, and as at February 8, 2022.

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

In March 2020, in connection with the completion of the acquisition of Granite Oil Corp. ("Granite"), the Group assumed the bank debt of Granite consisting of a revolving credit facility of CAD 42.5 million (the "Granite Facility"). In July 2020, the Group amended and extended the Canadian RBL to a facility size of CAD 350 million with a maturity extended until the end of May 2022. In December 2020, the Granite Facility was amended to a CAD 30 million revolving credit facility.

In June 2021, the Group consolidated the amounts outstanding under the Granite Facility into the Canadian RBL and the Granite Facility was terminated. As of June 30, 2021, the Canadian RBL was amended to a facility size of CAD 300 million with a maturity extended until the end of May 2023. Under the Canadian RBL, the Group had the requirement, to hedge 40% of forecast Canadian oil production from June 30, 2021, to December 31, 2021.

The borrowing base availability under the International RBL was agreed in November 2021 at approximately USD 100 million of which USD 4 million was drawn as at December 31, 2021. The borrowing base availability under the Canadian RBL was CAD 300 million of which CAD 120 million was drawn as at December 31, 2021.

In February 2022, IPC completed the issuance of USD 300 million of senior unsecured bonds (the "Bonds"), which mature in February 2027 and have a fixed coupon rate of 7.25 percent per annum, payable in semi-annual instalments. The Group used a portion of the proceeds of the Bonds to fully repay the Canadian RBL and the International RBL, which were then cancelled. At the same time, the Group entered into a revolving credit facility of CAD 75 million (the "Canadian RCF") in connection with its oil and gas assets in Canada. The Canadian RCF has a maturity of February 2024.

The amounts drawn under the International RBL and the Canadian RBL as at December 31, 2021, are classified as non-current as there are no mandatory repayments within the next twelve months.

An amount of USD 1,806 thousand drawn under the France Facility as at December 31, 2021 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the financing facilities as at December 31, 2021 and 2020.

The net debt and the movements in net debt can be summarized as follows:

USD Thousands	Cash	Lease liabilities	Bank loans due before 1 year	Bank loans due after 1 year	Total
Net debt as at January 1, 2021	**6,498**	**(2,018)**	**(22,982)**	**(304,709)**	**(323,211)**
Granite Facility	–	–	22,982	–	22,982
France Facility	–	–	(1,806)	1,806	–
Cash flows	12,368	–	–	192,837	205,205
Lease liabilities	–	354	–	–	354
Currency translation adjustments	(56)	–	–	(1,249)	(1,305)
Net debt as at December 31, 2021	**18,810**	**(1,664)**	**(1,806)**	**(111,315)**	**(95,975)**
Net debt (excluding lease liabilities)					**(94,311)**

USD Thousands	Cash	Lease liabilities	Bank loans due before 1 year	Bank loans due after 1 year	Total
Net debt as at January 1, 2020	15,571	(2,750)	–	(247,074)	(234,253)
Granite Acquisition (see Note 9)	–	–	(27,649)	–	(27,649)
Cash flows	(8,736)	–	7,585	(49,134)	(50,285)
Lease liabilities	–	732	–	–	732
Currency translation adjustments	(337)	–	(2,918)	(8,501)	(11,756)
Net debt as at December 31, 2020	**6,498**	**(2,018)**	**(22,982)**	**(304,709)**	**(323,211)**
Net debt (excluding lease liabilities)					**(321,193)**

20. PROVISIONS

USD Thousands	Asset retirement obligation	Farm-in obligation	Pension obligation	Other	Total
January 1, 2021	192,701	4,350	5,558	1,540	204,149
Additions[1]	15,993	–	293	159	16,445
Unwinding of asset retirement obligation discount	11,488	–	–	–	11,488
Changes in estimates	(17,952)	600	(578)	–	(17,930)
Payments	(3,945)	(601)	(629)	(277)	(5,452)
Reclassification[2]	1,414	–	–	–	1,414
Currency translation adjustments	(3,337)	(150)	(196)	(65)	(3,748)
December 31, 2021	**196,362**	**4,199**	**4,448**	**1,357**	**206,366**
Non-current	190,607	2,399	4,448	1,357	**198,811**
Current	5,755	1,800	–	–	**7,555**
Total	**196,362**	**4,199**	**4,448**	**1,357**	**206,366**

[1] The addition of USD 15,993 thousand relates to the increased decommissioning liability relating to the additional 25% working interest in the Bertam field, Malaysia. The majority of this additional liability is covered by secured amounts transferred on assignment of the working interest. (Also see Notes 1 and 12)
[2] The reclassification of the asset retirement obligation related to the 2021 payment to the asset retirement obligation fund in respect of the Bertam asset, Malaysia (see Note 12).

USD Thousands	Asset retirement obligation	Farm-in obligation	Pension obligation	Other	Total
January 1, 2020	176,305	6,720	4,413	2,399	189,837
Granite Acquisition	4,498	–	–	–	4,498
Additions	–	–	603	1,269	1,872
Unwinding of asset retirement obligation discount	10,837	–	–	–	10,837
Changes in estimates	(2,563)	(622)	703	–	(2,482)
Payments	(4,324)	(1,814)	(636)	(2,179)	(8,953)
Reclassification[1]	1,967	–	–	–	1,967
Currency translation adjustments	5,981	66	475	51	6,573
December 31, 2020	**192,701**	**4,350**	**5,558**	**1,540**	**204,149**
Non-current	187,012	3,107	5,558	1,268	**196,945**
Current	5,689	1,243	–	272	**7,204**
Total	**192,701**	**4,350**	**5,558**	**1,540**	**204,149**

[1] The reclassification of the asset retirement obligation related to the 2020 payment to the asset retirement obligation fund in respect of the Bertam asset, Malaysia (see Note 12).

The farm-in obligation relates to future payments for historic costs on Block PM307 in Malaysia payable on reaching certain Bertam field production milestones.

In calculating the present value of the asset retirement obligation provision, a blended rate of 6% (2020: 6%) was used, based on a credit risk adjusted rate.

21. PENSION LIABILITY

The Group operates a pension plan for employees in Switzerland that is managed through a private pension plan. The amount recognized in the balance sheet associated with the Swiss pension plan is as follows:

USD Thousands	December 31, 2021	December 31, 2020
Present value of defined benefit obligation	14,714	15,316
Fair value of plan assets	(10,266)	(9,758)
Pension obligation, ending balance	**4,448**	**5,558**

The movement in the defined benefit obligation over the year is as follows:

USD Thousands	For the year ended December 31, 2021	For the year ended December 31, 2020
Opening balance	15,316	10,760
Current service cost	636	786
Additional contributions paid by employees	237	1,920
Ordinary contributions paid by employees	419	424
Interest expense on defined benefit obligation	29	27
Actuarial loss on defined benefit obligation	(552)	777
Administration costs	13	12
Benefits paid from plan assets	(485)	(452)
Past service cost	(366)	(206)
Foreign exchange loss	(533)	1,268
Defined benefit obligation, ending balance	**14,714**	**15,316**

The weighted average duration of the defined benefit obligation is 18.6 years. There is no maturity profile since the average remaining life before active employees reach final age according to the plan is 10.4 years.

The movement in the fair value of the plan assets over the year is as follows:

USD Thousands	For the year ended December 31, 2021	For the year ended December 31, 2020
Opening balance	9,758	6,347
Additional contributions paid by employees	237	1,920
Ordinary contributions paid by employer	629	636
Ordinary contributions paid by employees	419	424
Interest income on plan assets	19	16
Return on plan assets excluding interest income	26	73
Foreign exchange gain	(337)	794
Benefits paid from plan assets	(485)	(452)
Fair value of plan assets, ending balance	**10,266**	**9,758**

The plan assets are under an insurance contract comprised entirely of free funds and reserves, such as fluctuation reserves and employer contribution reserves, for which there is no quoted price in an active market.

The amount recognized in the income statement associated with the Group's pension plan is as follows:

USD Thousands	For the year ended December 31, 2021	For the year ended December 31, 2020
Current service cost	636	786
Interest expense on defined benefit obligation	29	27
Administration costs	13	12
Past service cost	(366)	(206)
Interest income on plan assets	(19)	(16)
Total expense recognized	**293**	**603**

The expense associated with the Group's pension plan of USD 293 thousand was included within general and administrative expenses. The Group also recognized in other comprehensive income a USD 578 thousand net actuarial gain on defined benefit obligations and pension plan assets.

The principal actuarial assumptions used to estimate the Group's pension obligation are as follows:

USD Thousands	For the year ended December 31, 2021	For the year ended December 31, 2020
Discount rate	0.20%	0.20%
Inflation rate	1.00%	1.00%
Future salary increase	1.00%	1.00%
Future pension increases	0.00%	0.00%
Retirement ages, male ('M') and female ('F')	M65/F64	M65/F64

Assumptions regarding future mortality are set based on actuarial advice in accordance with the BVG 2015 GT generational published statistics and experience in Switzerland. The discount rate is determined by reference to the yield on high quality corporate bonds. The rate of inflation is based on the expected value of future annual inflation adjustments in Switzerland. The rate for future salary increases is based on the average increase in the salaries paid by the Group, and the rate of pension increases is based on the annual increase in risk, retirement and survivors' benefits.

The sensitivity of the defined benefit obligation to changes in the weighted principal assumptions is:

	Change in assumption	Increase in assumption	Decrease in assumption
Discount rate	0.50%	Decrease by 8.6%	Increase by 10.0%
Salary growth rate	0.50%	Increase by 0.6%	Decrease by 0.6%
Life Expectancy	One year	Increase by 1.4%	Decrease by 1.5%

The above sensitivity analyses are based on a change in an assumption while holding all other assumptions constant. In practice, this is unlikely to occur, and changes in some of the assumptions may be correlated. When calculating the sensitivity of the defined benefit obligation to significant actuarial assumptions, the same method has been applied as when calculating the pension liability recognized within the consolidated balance sheet.

22. TRADE AND OTHER PAYABLES

USD Thousands	December 31, 2021	December 31, 2020
Trade payables	9,043	11,635
Joint operations creditors	20,201	14,135
Accrued expenses	45,329	34,453
Other	5,268	3,127
	79,841	**63,350**

23. FINANCIAL ASSETS AND LIABILITIES

Financial assets and liabilities by category

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

December 31, 2021 USD Thousands	Total	Financial assets at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Other assets[1]	35,753	35,753	–	–
Derivative instruments	1,159	–	–	1,159
Joint operation debtors	1,930	1,930	–	–
Other current receivables[2]	102,741	92,914	9,827	–
Cash and cash equivalents	18,810	18,810	–	–
Financial assets	160,393	149,407	9,827	1,159

[1] *See Note 12*
[2] *Prepayments are not included in other current assets, as prepayments are not deemed to be financial instruments*

December 31, 2021 USD Thousands	Total	Financial liabilities at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Non-current financial liabilities	109,219	109,219	–	–
Current financial liabilities	1,806	1,806	–	–
Derivative instruments	–	–	–	–
Joint operation creditors	20,201	20,201	–	–
Other current liabilities	19,404	19,404	–	–
Financial liabilities	150,630	150,630	–	–

December 31, 2020 USD Thousands	Total	Financial assets at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Other assets[1]	20,239	20,239	–	–
Derivative instruments	1,591	–	–	1,591
Joint operation debtors	1,792	1,792	–	–
Other current receivables[2]	59,992	54,935	5,057	–
Cash and cash equivalents	6,498	6,498	–	–
Financial assets	90,112	83,464	5,057	1,591

[1] *See Note 12*
[2] *Prepayments are not included in other current assets, as prepayments are not deemed to be financial instruments*

December 31, 2020 USD Thousands	Total	Financial liabilities at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Non-current financial liabilities	302,500	302,500	–	–
Current financial liabilities	22,982	22,982	–	–
Derivative instruments	2,746	–	–	2,746
Joint operation creditors	14,135	14,135	–	–
Other current liabilities	15,617	15,617	–	–
Financial liabilities	357,980	355,234	–	2,746

The carrying amount of the Group's financial assets approximate their fair values at the balance sheet dates.

For financial instruments measured at fair value in the balance sheet, the following fair value measurement hierarchy is used:
– Level 1: based on quoted prices in active markets;
– Level 2: based on inputs other than quoted prices as within level 1, that are either directly or indirectly observable;
– Level 3: based on inputs which are not based on observable market data.

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

December 31, 2021 USD Thousands	Level 1	Level 2	Level 3
Other current receivables	9,827	–	–
Derivative instruments – current	–	1,159	–
Financial assets	**9,827**	**1,159**	**–**
Derivative instruments – current	–	–	–
Financial liabilities	**–**	**–**	**–**

December 31, 2020 USD Thousands	Level 1	Level 2	Level 3
Other current receivables	5,057	–	–
Derivative instruments – current	–	1,591	–
Financial assets	**5,057**	**1,591**	–
Derivative instruments – current	–	2,746	–
Financial liabilities	–	**2,746**	–

24. MANAGEMENT OF FINANCIAL RISK

The Corporation's financial instruments are exposed to certain financial risks, including credit risk, liquidity risk, foreign exchange risk, commodity price risk and interest rate risk.

a) Credit risk

The exposure to credit risk arises through the failure of a customer or another third party to meet its contractual obligations to the Corporation. The Corporation believes that its maximum exposure to credit risk as at December 31, 2021, is the carrying value of its trade receivables. The Group's policy is to limit credit risk by limiting the counterparties to major oil and gas companies. Where it is determined that there is a credit risk for oil and gas sales, the policy is to require an irrevocable letter of credit for the full value of the sale. The policy on joint operation parties is to rely on the provisions of the underlying joint operating agreements to take possession of the licence or the partner's share of production for non-payment of cash calls or other amounts due.

As at December 31, 2021, the trade receivables amounted to USD 91,062 thousand and there is no recent history of default. The expected credit loss associated with these receivables is not significant. Cash and cash equivalents are maintained with banks having strong long-term credit ratings.

b) Liquidity risk

Liquidity risk is defined as the risk that the Group could not be able to settle or meet its obligations on time or at a reasonable price. Corporation treasury is responsible for liquidity, funding as well as settlement management. The Corporation has in place a planning and forecasting process to help determine the funds required to support the Corporation's normal operating requirements on an ongoing basis. The Corporation ensures that there is sufficient available capital to meet its short-term business requirements, taking into account its anticipated cash flows from operations and its holdings of cash and cash equivalents, including bond proceeds. The Corporation has credit facilities in place to assist with meeting its cash flow needs as required (Note 19).

The table below analyses the Group's financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet date to the contractual maturity date. Loan repayments are made upon a net present value calculation of the assets' future cash flows. No loan repayments are currently forecast under this calculation.

USD Thousands	December 31, 2021	December 31, 2020
Non-current		
Repayment within 2 - 5 years:		
- Bank loans	111,315	304,709
	111,315	**304,709**
Current		
Repayment within 6 to 12 months:		
- Bank loans	1,806	22,982
Repayment within 6 months:		
- Trade payables	9,043	11,635
- Joint operation creditors	20,201	14,135
- Other current liabilities	5,268	3,127
- Current tax liabilities	5,093	184
	41,411	**52,063**

c) Foreign exchange risk

The Group operates internationally and is exposed to foreign exchange risk arising from various currencies, primarily with respect to EUR and CAD. The Group's risk management objective is to manage cash flow risk related to foreign denominated cash flows. The Corporation is exposed to currency risk related to changes in rates of exchange between foreign denominated balances and the functional currencies of the Group's principal operating subsidiaries. The Group's revenues are denominated in US dollars, while most of its operating and capital expenditures are denominated in the local currencies. A significant change in the currency exchange rates between the US dollar and foreign currencies could have a material effect on the Group's net earnings and on other comprehensive income.

The following tables summarize the effects that a change in these currencies against the US Dollar would have on operating result and equity through the conversion of the income statements of the Group's subsidiaries from functional currency to the presentation currency US Dollar for the years ended at December 31, 2021 and 2020.

Shift of currency exchange rates USD Thousands	Average rate 2021	USD weakening 10%	USD strengthening 10%
Operating profit in the financial statements		197,956	197,956
EUR /USD	0.8450	0.7681	0.9294
CAD/USD	1.2536	1.1396	1.3790
Total effect on operating profit		**(16,961)**	**16,961**

Shift of currency exchange rates USD Thousands	Average rate 2020	USD weakening 10%	USD strengthening 10%
Operating profit in the financial statements		(96,775)	(96,775)
EUR /USD	0.8762	0.7965	0.9638
CAD/USD	1.3412	1.2193	1.4753
Total effect on operating profit		**9,714**	**(9,714)**

d) Commodity price risk

The Group is subject to price risk associated with fluctuations in the market prices for oil and gas. Prices of oil and gas are affected by the normal economic drivers of supply and demand as well as the financial investors and market uncertainty. Factors that influence these include operational decisions, natural disasters, economic conditions, political instability or conflicts or actions by major oil exporting countries. Price fluctuations can affect the Corporation's financial position.

Commodity price risk is the risk that future cash flows will fluctuate as a result of changes in the price of oil and natural gas. Commodity prices are impacted by world economic events that affect supply and demand, which are generally beyond the Group's control. Changes in crude oil prices may significantly affect the Corporation's results of operations, cash generated from operating activities, capital spending and the Corporation's ability to meet its obligations. The majority of the Corporation's production is sold under short-term contracts; consequently the Group is at risk to near term price movements. The Corporation manages this risk by constantly monitoring commodity prices and factoring them into operational decisions, such as contracting or expanding its capital expenditures program.

The Corporation enters into certain risk management contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These risk management contracts are not used for trading or speculative purposes. The Corporation has designated its risk management contracts as effective accounting hedges, and thus has applied hedge accounting. As a result, all risk management contracts are recorded at fair value at each reporting period with the change in fair value being recognized on the statement of comprehensive income.

The outstanding derivative instruments can be specified as follows:

Fair value of outstanding derivative instruments in the balance sheet

	December 31, 2021		December 31, 2020	
USD Thousands	Assets	Liabilities	Assets	Liabilities
Oil price hedge	–	–	–	2,743
Gas price hedge	1,159	–	1,591	3
Total	**1,159**	–	**1,591**	**2,746**
Non-current	–	–	–	–
Current	1,159	–	1,591	2,746
Total	**1,159**	–	**1,591**	**2,746**

The Group had gas price sale financial hedges outstanding as at December 31, 2021, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
January 1, 2022 – March 31, 2022	20,000	AECO Swap	CAD 4.15/GJ
April 1, 2022 – September 30, 2022	20,000	AECO Swap	CAD 3.14/GJ

The Group had no oil price sale financial hedges outstanding as at December 31, 2021.

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

The table below summarizes the effect that a change in the oil and gas price would have had on the net result and equity at December 31, 2021 and 2020:

2021 Net result (USD Thousands)	146,059	146,059
Possible shift (%)	(10%)	10%
Total effect on net income (USD Thousands)	**(54,368)**	**54,368**

2020 Net result (USD Thousands)	(77,941)	(77,941)
Possible shift (%)	(10%)	10%
Total effect on net income (USD Thousands)	**(23,081)**	**23,081**

e) Interest rate risk

The Group's exposure to interest rate risk arises from both the interest rate impact on its cash and cash equivalents as well as on its debt facilities. As at December 31, 2021, the Group's long-term debt is comprised of partially floating rate debt tied to LIBOR. As such, changes in interest rate will have an impact on interest expense.

The total interest expense for 2021 amounted to USD 12,867 thousand (2020: USD 13,401 thousand). A 100 basis point shift in the interest rate would have resulted in a change in the total interest expense for the year of USD 2,477 thousand (2020: USD 3,255 thousand).

25. MANAGEMENT OF CAPITAL RISK

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

No significant changes were made in the objectives, policies or procedures during the year ended December 31, 2021 or in the comparative periods.

Through the ongoing management of its capital, the Corporation will modify the structure of its capital based on changing economic conditions in the jurisdictions in which it operates. In doing so, the Corporation may issue new shares or debt, buy back issued shares, or pay off any outstanding debt.

26. SALARY AND OTHER COMPENSATION EXPENSES

a) Employee compensation expenses

The following table provides a breakdown of gross salaries, short-term benefits, share-based compensation and other compensation expenses included in the consolidated statement of comprehensive income (loss):

USD Thousands	2021	2020
Salaries, bonuses and other short-term benefits	44,033	40,914
Security social costs	5,556	6,387
Share-based incentive plans[1]	6,457	4,798
	56,046	**52,099**

[1] *Vested during the period and based on IFRS 2 valuation (see Note 18)*

b) Remuneration of Directors and Senior Management

Remuneration of Directors and Senior Management includes all amounts earned and awarded to the Group's Board of Directors and Senior Management. Senior Management includes the Group's President and Chief Executive Officer, Chief Financial Officer, General Counsel and Corporate Secretary, Chief Operating Officer, Senior Vice President Canada, Vice President of Asset Management and Corporate Planning Canada and Vice President of Corporate Planning and Investor Relations.

Directors' fees include Board and Committee fees. Senior Management's remuneration includes salary, short-term benefits, bonuses and any other compensation earned in 2020 and in 2021.

USD Thousands	2021	2020
Directors' fees	650	686
Senior Management's salaries, bonuses and other short-term benefits	4,818	6,989
Share-based incentive plans paid to Senior Management	641	118
	6,109	**7,793**

27. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

In Canada, an oil pipeline from the Onion Lake Thermal field to the Husky Alberta Gathering System has been built by Husky Midstream ("Husky") for the exclusive use of IPC. Onion Lake Thermal oil production is planned to be blended with condensate before being transported via the pipeline and is therefore expected to attract improved realised prices as a result of the blended oil. The pipeline is also expected to improve the reliability and uptime of the transportation and production at Onion Lake Thermal. The initial investment in the pipeline was met by Husky and is to be recovered through an agreed tariff charged to IPC. IPC has committed to a firm transportation service for 15 years from commencement of service, with total tariffs committed as shown in the table below:

	2022[1]	2023	2024	2025	2026	Thereafter
Transportation service (MCAD)	22.5	27.3	28.0	28.4	29.0	300.9

[1] *Assuming commissioning of the pipeline and commencement of the service occurs during the first quarter of 2022*

In Malaysia, IPC has an obligation to make payments towards historic costs on Block PM307 payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves has been provided for in the Group's Balance Sheet (see Note 20).

28. RELATED PARTIES

Lundin Energy has charged the Group USD 636 thousand in respect of office space rental and USD 1,508 thousand in respect of shared services provided during the year 2021.

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.

29. IMPACT OF COVID-19

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified in IPC's Management's Discussion and Analysis for the year ended December 31, 2021 ("MD&A") and previous Annual Information Form, financial reports and MD&A that result from a reduction in demand for oil and gas consumption and/or lower commodity prices and/or reliance on third parties. The extent to which Covid-19 impacts IPC's business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the duration and spread of the current and any future Covid-19 outbreaks, their severity, the actions taken to contain such outbreaks or treat their impact, and how quickly and to what extent normal economic and operating conditions resume and their impacts to IPC's business, results of operations and financial condition. Even after the Covid-19 outbreaks have subsided, IPC may continue to experience materially adverse impacts to IPC's business as a result of the global economic impact.

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

30. SUBSEQUENT EVENTS

In January 2022, the Group entered into oil price sale financial hedges to hedge the WCS/WTI Differential, hedging a volume of 11,900 bbl/day at an average of USD 13.06/bbl for the period March 1 to June 30, 2022 and a volume of 16,000 bbl/day at an average of USD 13.04/bbl for the period July 1 to December 31, 2022.

In January 2022, the Group entered into further gas price sale financial hedges to hedge the AECO Swap, hedging a volume of 15,000 GJ/day at an average of CAD 3.77/GJ for the period April 1 to September 30, 2022.

In February 2022, IPC completed the issuance of USD 300 million of senior unsecured bonds, which mature in February 2027 and have a fixed coupon rate of 7.25 percent per annum, payable in semi-annual instalments. The Group used a portion of the proceeds of the Bonds to fully repay the Canadian RBL and the International RBL, which were then cancelled. At the same time, the Group entered into a revolving credit facility of CAD 75 million (the "Canadian RCF") in connection with its oil and gas assets in Canada. The Canadian RCF has a maturity of February 2024.

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

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

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International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended and year ended December 31, 2021

International Petroleum Corp.

Management's Discussion and Analysis
For the three months ended and year ended December 31, 2021

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt" which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. 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 21.

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 33.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2021, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2021, price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2021, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2021, price forecasts.

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

The Covid-19 virus and the restrictions and disruptions related to it had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. Although demand, commodity prices and share prices have recovered, there can be no assurance that these effects will not resume or that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures. See "Risks and Uncertainties".

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated February 8, 2022, 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 audited consolidated financial statements and accompanying notes for the year ended December 31, 2021 ("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 ("TSX") 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 2600, 595 Burrard Street, P.O. Box 49314, Vancouver, BC V7X 1L3, Canada and its business address is Suite 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

Basis of Preparation

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

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

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

	December 31, 2021		December 31, 2020	
	Average	Period end	Average	Year end
1 EUR equals USD	1.1835	1.1326	1.1413	1.2271
1 USD equals CAD	1.2536	1.2708	1.3412	1.2740
1 USD equals MYR	4.1433	4.1660	4.2026	4.0209

HIGHLIGHTS

2021 Business and Financial Highlights

- Average net production of approximately 46,800 barrels of oil equivalent (boe) per day (boepd) for the fourth quarter of 2021 was above the high end of the third quarter of 2021 guidance range for the period (46% heavy crude oil, 18% light and medium crude oil and 36% natural gas)[1].
- Full year 2021 average net production was 45,500 boepd above the high end of guidance and year end exit rate was above 46,000 boepd.
- Production from the new sustaining Pad D' at Onion Lake Thermal, Canada successfully brought online in the third quarter of 2021, with initial performance ahead of expectations and five production infill wells drilled at Onion Lake Thermal during the fourth quarter of 2021.
- Increased working interest in the Bertam Field, Malaysia from 75% to 100% in April 2021.
- Exceptional operational performance at the Bertam Field during 2021, with greater than 99% uptime and the successful increase of Bertam FPSO water handling capacity from 17,000 to 24,000 barrels of water per day in Q3 2021.
- Drilling operations on the A15 sidetrack well at the Bertam Field commenced in December 2021.
- Second annual Sustainability Report published in Q2 2021.
- Proved plus probable (2P) reserves as at December 31, 2021 of 270 million boe (MMboe), with a reserves life index (RLI) of 16 years[1][2].
- Contingent resources (best estimate, unrisked) as at December 31, 2021 of 1,410 MMboe[1][2].
- Operating costs per boe of USD 15.1 for the fourth quarter of 2021 and USD 15.0 for the full year compared to full year guidance of USD 15.5 per boe.[3]
- Record high operating cash flow (OCF) generation for the fourth quarter and full year 2021 amounted to MUSD 111 and MUSD 337 respectively.[3]
- Capital and decommissioning expenditures of MUSD 48 for the full year 2021, slightly below guidance of MUSD 50 following the re-phasing of drilling projects in Malaysia into the first quarter of 2022.
- Record high free cash flow (FCF) generation for the fourth quarter and full year 2021 amounted to MUSD 87 and MUSD 263 respectively.[3]
- Net debt of MUSD 94 as at December 31, 2021, down from MUSD 161 at the end of the third quarter of 2021 and down from MUSD 321 as at December 31, 2020.[3]
- Net debt to 12 month rolling EBITDA ratio as at December 31, 2021 was 0.3 times.[3]
- Net result of MUSD 67 for the fourth quarter of 2021 and MUSD 146 for the full year 2021.

	Three months ended December 31		Year ended December 31	
USD Thousands	2021	2020	2021	2020
Revenue	215,296	103,353	666,409	324,164
Gross profit / (loss)	79,469	(60,570)	210,321	(83,986)
Net result	66,918	(45,250)	146,059	(77,941)
Operating cash flow[3]	110,687	46,019	336,732	119,423
Free cash flow[3]	86,960	28,571	262,884	9,342
EBITDA[3]	110,087	43,004	330,754	108,451
Net Debt[3]	94,312	321,193	94,312	321,193

2022 Business Plan Highlights

- Forecast cumulative FCF for 2022 to 2026 of approximately MUSD 900 to MUSD 1,800 (Brent USD 65 to 95 per barrel) generating estimated average annual free cash flow yield over the five year period of between 18% and 36%.[3][7]
- Approved new capital allocation plan where, from and including 2022, IPC intends to distribute to shareholders up to 40% of the FCF generated by IPC above achieved average Brent oil prices of USD 55 per barrel.
- IPC's inaugural USD 300 million bond issued on February 1, 2022, with a portion of the bond proceeds used to fully repay and cancel IPC's existing reserve-based lending credit facilities.

OPERATIONS REVIEW

Business Overview

Market conditions for oil and gas producers rebounded strongly in 2021 from the lows experienced in 2020, finishing on a high in the final quarter of 2021 with an average Brent oil price of USD 80 per barrel. Full year 2021 average Brent prices averaged USD 71 per barrel, well in excess of the full year 2020 Brent oil prices average of USD 42 per barrel.

Proactive supply management by the OPEC+ group, led by Saudi Arabia, has more than rebalanced the market. Excess oil inventory levels are reported to have drawn back down well below pre-pandemic levels, and now sit below the five year average. The recovery in oil demand remains on track and it now feels like we are approaching the beginning of the end of the pandemic. Covid-19 defences are incomparable to this time last year with the vaccination and testing programs we now have in place. This should bode well for oil demand going forward as the final wave of mobility restrictions eases and OPEC+ production curtailment fully unwind, noting that some producers are facing challenges in meeting their increased quotas.

In Canada, fourth quarter 2021 Western Canadian Select (WCS) crude price differentials averaged below USD 15 per barrel and forward markets into 2022 and 2023 are pricing the WCS differential at below USD 14 per barrel. Completion and placement into service of Enbridge's Line 3 replacement pipeline in the fourth quarter of 2021 as well as the positive construction progress on the TransMountain pipeline expansion project is providing a much more constructive outlook for Canadian oil market egress relative to the tightness we have witnessed over the past several years. IPC has positioned itself well to benefit from this fundamental improvement in market conditions and has decided to take advantage of this by hedging approximately 60% of our WTI/WCS differential exposure at approximately USD 13 per barrel for the remainder of 2022. No other oil hedges are in place providing full exposure to the strength we are seeing in both the Brent and WTI benchmarks.

Gas markets have also strengthened driven by a combination of increasing demand, lower supply and warmer than average summer temperatures that diverted gas supply away from injecting into storage. Fourth quarter 2021 average Empress gas prices were CAD 5.00 per Mcf and forward 2022 prices sit above CAD 3.50 per Mcf. IPC has hedged AECO gas prices, 19,000 Mcf per day at CAD 4.40 CAD per Mcf in Q1 2022 and 33,000 Mcf per day at CAD 3.60 per Mcf in Q2 and Q3 2022.

IPC benefits from a well balanced mix of production comprising approximately 48% Canadian crude oil, 36% Canadian gas and 16% Brent weighted oil. With synchronized strength in pricing across the entire energy complex, combined with IPC delivering operational excellence above the high end of our forecasts, IPC has been able to deliver our best ever quarterly and annual financial performance since our launch in 2017.

We were very pleased with IPC's first USD 300 million bond, issued on February 1, 2022, accessing the debt capital markets at a favourable time. We used a portion of the proceeds of the bond to fully repay and cancel our existing reserve-based lending facilities and at the same time, we put in place a new CAD 75 million revolving credit facility for financial flexibility in Canada. We strongly believe that the winners in the next phase of the energy transition in the upstream oil and gas industry will be the companies able to access diverse sources of funding. Whilst we do not have an imminent acquisition, we believe that being able to demonstrate to sellers that IPC has the financial strength on its balance sheet, will enable IPC to access a greater universe of opportunities whilst differentiating us from our peers in terms of certainty of being able to close transactions.

We have created significant value from acquisition for all of our stakeholders having concluded four acquisitions in the past four years and will remain opportunistic in our approach with respect to further M&A activity focusing on securing additional high quality resources.

Fourth Quarter and Full Year 2021 Highlights

During the fourth quarter of 2021, our assets delivered average net production of 46,800 boepd.[1] Production for the full year 2021 averaged 45,500 boepd.[1] In all four quarters of 2021, IPC has delivered production above our original high end guidance. This was made possible by the very high uptime performance across all our assets as well as the earlier than forecast production contribution from the newly commissioned Pad D' at Onion Lake Thermal.

Our operating costs per boe for the fourth quarter of 2021 was USD 15.1.[3] Full year operating costs per boe of 15.0 was below our latest guidance of USD 15.50 per boe, largely driven by the production outperformance.

Operating cash flow generation for the fourth quarter of 2021 was USD 111 million, a record high for IPC.[3] Full year operating cash flow amounts to USD 337 million, above our high end guidance and a record for IPC.

Capital and decommissioning expenditures for the full year was USD 48 million, USD 2 million below guidance largely the result of re-phasing into 2022.

Free cash flow generation was exceptionally strong at USD 87 million during the fourth quarter of 2021 and USD 263 million for the full year, a record quarterly and full year result for IPC and above our latest high end guidance.[3] This represents close to 26% of IPC's current market capitalization.

Net debt reduced more than 70% during 2021 to USD 94 million as at December 31, 2021.[3] Net debt to EBITDA drops to 0.3 times at year-end 2021 from 3 times at the year-end 2020 (trailing 12 months).

Capital Allocation Plans
We are also pleased to announce IPC's 2022 capital allocation plans, given our strong forecast liquidity position resulting from continued operational performance and strong commodity prices. Based on our current business plans and assumptions, IPC plans to distribute to shareholders up to 40% of the free cash flow generated by IPC above achieved average Brent oil prices of USD 55 per barrel, provided that IPC's net debt to EBITDA ratio is at or below 1 time.[(3)(7)] These shareholder distributions are planned to be implemented by continued share repurchases under the previously announced share repurchase program as well as the consideration by IPC of other forms of shareholder distributions, subject to further applicable regulatory and corporate approvals.

Share Repurchase Program
In Q4 2021, IPC announced a share repurchase program, with the ability to repurchase up to approximately 11.1 million IPC common shares over the twelve month period to December 2022. IPC repurchased in December 2021 and subsequently cancelled approximately 1.3 million IPC shares, at an average purchase price of approximately SEK 49.5 (or around CAD 6.95) per share. By the end of January 2022, IPC repurchased a further approximately 1.0 million IPC shares of which 726,676 shares have been cancelled.

Environmental, Social and Governance ("ESG") Performance
Responsible operatorship and ensuring that we adhere to the highest principles of business conduct have been an integral part of how we do business since the creation of IPC in 2017. Over the past five years, IPC has rapidly grown our business with the completion of three acquisitions in Canada, an acquisition in Malaysia in addition to significant organic investments into those businesses. In parallel, we have made a concerted effort to further develop and improve our sustainability strategy. An important part of this journey involves the measurement and transparent reporting of a broad range of ESG metrics. Alongside the publication of our second quarter 2021 financial report, we were very pleased to publish our second Sustainability Report that was fully GRI compliant. We encourage everyone to read it and see first-hand the good work that is being done within our company. As previously announced, IPC targets a reduction of our net GHG emissions intensity by the end of 2025 to 50% of the Corporation's 2019 baseline.

During the fourth quarter of 2021 and for the full year 2021, IPC recorded no material safety or environmental incidents. In response to the Covid-19 pandemic, we remain focused on protecting the health and safety of our employees, contractors and other stakeholders, while also working to ensure business continuity. Throughout 2021, IPC continued the health protocols implemented across the organization.

Reserves and Resources
As at the end of December 2021, IPC's 2P reserves are 270 MMboe.[(1)(2)] During 2021, IPC replaced 91% of production through a combination of reserve additions and the acquisition of an additional 25% working interest in the Bertam field, Malaysia. The reserves life index (RLI) as at December 31, 2021, is approximately 16 years.[(2)]

Based on independent qualified reserve auditor reports, the net present value (NPV)[(2)(4)] of IPC's 2P reserves as at December 31, 2021 was USD 2,522 million. IPC's net asset value (NAV)[(2)(5)] as at December 31, 2021 was USD 2,428 million. IPC's NAV per share[(2)(6)] was SEK 143 as at December 31, 2021.

In addition, IPC's best estimate contingent resources (unrisked) as at end December 2021 have increased by more than 300 MMboe to 1,410 MMboe.[(1)(2)]

The biggest single contributor to the increase in contingent resource estimates comes from the Blackrod project in Canada.[(1)(2)] IPC commissioned a third party independent qualified reserves evaluator report from Sproule Associates Ltd. (Sproule) on the contingent resources at Blackrod Phase I as at December 31, 2021. Full field best estimate contingent resources (unrisked) increased from 987 MMboe as at end December 2020 to 1,283 MMboe as at end December 2021. Phase I best estimate contingent resources (unrisked) increased from 178 MMboe to 217 MMboe as at end December 2021. Development capital expenditure to first oil is estimated at USD 540 million (unrisked). The Phase I development concept has been further optimised to include initial production capacity of 20,000 bopd rising to 30,000 bopd. First oil is assumed to be four to five years after final investment decision with production ramping up to 30,000 bopd thereafter. The breakeven oil price estimated by IPC assuming a 10% discount rate is a WTI price of approximately USD 50 per barrel. Using Sproule's price forecasts as at December 31, 2021, the net present value at a 10% discount rate (after tax, unrisked) of Blackrod Phase I as at December 31, 2021 is USD 609 million. IPC plans to mature the Blackrod Phase I project during 2022 through FEED studies in parallel with the continuation of production from well pair three.

2022 Budget and Production Guidance

We are pleased to announce our 2022 average net production guidance is 46,000 to 48,000 boepd.[1] We forecast operating costs for 2022 to be USD 15.2 per boe.[3]

We also forecast significant free cash flow generation based on our 2P reserves base of an aggregate of more than USD 900 million to USD 1,800 million over the period of 2022 to 2026, without taking into account development of our contingent resources or any further potential acquisitions.[2][3][7]

Our 2022 capital expenditure budget is USD 127 million, as IPC focuses our 2022 strategy on strong free cash flow generation whilst growing our production and maturing our significant contingent resource base. The 2022 budget includes the commencement of investment at Onion Lake Thermal on the next sustaining Pad L as well as further infill drilling, Suffield oil N2N drilling, Phase I development at the Ferguson asset and Blackrod FEED studies as well as continued production from well pair three in Canada. We plan to complete the A15 sidetrack and ESP pump upsizing campaign in Malaysia as well as to start the Phase I development of the Villeperdue West project in France. Given that IPC operates 100% of these projects, significant flexibility is retained to amend our plans based on the development of commodity prices.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the material change report dated February 8, 2022 (MCR) available on IPC's website at www.international-petroleum.com and filed on the date of this press release under IPC's profile on SEDAR at www.sedar.com.
(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of NPV, are further described in the MCR.
(3) Non-IFRS measure, see "Non-IFRS Measures" below and in the MD&A.
(4) NPV is after tax, discounted at 8% and based upon the forecast prices and other assumptions further described in the MCR. See "Reserves and Resources Advisory" below.
(5) NAV is calculated as NPV less net debt of USD 94 million as at December 31, 2021.
(6) NAV per share is based on 155,037,454 IPC common shares, being 155,198,105 IPC common shares outstanding as at December 31, 2021 less 1,160,651 IPC common shares held in treasury for cancellation in early January 2022.
(7) Estimated free cash flow generation is based on IPC's current business plans over the period of 2022 to 2026. Assumptions include average net production over that period of approximately 47 Mboepd, average Brent oil prices of USD 65 to 95 per boe escalating by 2% per year, average gas prices of CAD 3.00 per thousand cubic feet, and average Brent to Western Canadian Select differentials as estimated by IPC's independent reserves evaluator and as further described in the MCR. Free cash flow yield is based on IPC's market capitalization at close February 4, 2022 (60.0 SEK/share, 9.1 SEK/USD, USD 1,014 million). 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. See "Cautionary Statement Regarding Forward-Looking Information" below.

Operations Overview

Reserves and Resources

The 2P reserves attributable to IPC oil and gas assets are 270 MMboe as at December 31, 2021, as certified by independent third party reserves auditors. The reserves life index (RLI) as at December 31, 2021, is approximately 16 years. Best estimate contingent resources as at December 31, 2021, are 1,410 MMboe (unrisked). See "Reserves and Resources Advisory" below.

IPC remains focused on organic growth, maturing and executing opportunities across all our operated assets. IPC initially set a limited capital budget for 2021, with the focus on free cash flow delivery to the business. At the end of the second quarter in 2021, with strong production performance and improved market conditions strengthening free cash flow generation, IPC increased the capital expenditure budget to allow for infill drilling and optimisation projects in both Malaysia and Canada. In Canada, production sustaining Pad D' and five infill wells have been successfully delivered and brought online at Onion Lake Thermal. In Malaysia, the A15 sidetrack and Electric Submersible Pump (ESP) upsizing campaign commenced in Q4 2021; drilling operations are ongoing with first production from the project expected in the first quarter of 2022. IPC remains focused on free cash flow generation and, notwithstanding the inclusion of the incremental capital expenditure projects in 2021, IPC delivered free cash flow well in excess of our original high end Capital Markets Day 2021 guidance.

Production

The average net production during Q4 2021 was 46,800 boepd. This is the fourth quarter in succession of delivering production above our high end CMD guidance. In Canada, the exceptional production performance continued with high levels of production optimisation activity driving our gas production to the high end of guidance. All five new production infill wells have been brought online at Onion Lake Thermal. In addition, strong performance from the Malaysian and French assets continued in Q4 2021 with excellent operational performance and facility uptime at the Bertam field in Malaysia and stable production performance in France with optimisation activity continuing to offset natural production declines.

With the exceptional operational performance through 2021, IPC achieved a net annual average production of 45,500 boepd, a 500 boepd increase from our previous guidance of above 45,000 boepd and six percent above our original high end CMD guidance.

The production during Q4 2021 with comparatives is summarized below:

Production in Mboepd	Three months ended December 31		Year ended December 31	
	2021	2020	2021	2020
Crude oil				
Canada – Northern Assets	14.2	12.0	12.8	10.6
Canada – Southern Assets	8.5	8.4	8.6	7.1
Malaysia	4.5	4.2	4.4	4.4
France	2.9	2.9	3.0	2.8
Total crude oil production	**30.1**	27.5	**28.8**	24.9
Gas				
Canada – Northern Assets	0.1	0.1	0.1	0.1
Canada – Southern Assets	16.6	17.3	16.6	17.1
Total gas production	**16.7**	17.4	**16.7**	17.2
Total production	**46.8**	44.9	**45.5**	42.1
Quantity in MMboe	**4.31**	4.13	**16.61**	15.42

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

CANADA

Production in Mboepd	WI	Three months ended December 31		Year ended December 31	
		2021	2020	2021	2020
- Oil Onion Lake Thermal	100%	11.5	10.6	10.6	9.5
- Oil Suffield	100%	7.5	7.2	7.5	5.9
- Oil Ferguson	100%	1.0	1.2	1.1	1.2
- Oil Other	50-100%	2.7	1.4	2.2	1.1
- Gas	99.7%[1]	16.7	17.4	16.7	17.2
Canada		**39.4**	37.8	**38.1**	34.9

[1] *On a well count basis*

Production

Net production from the Canadian assets during Q4 2021 was above the high end of CMD guidance at 39,400 boepd with continued strong performance and high production uptime at all the oil and gas producing assets. In Q4 2021, high levels of production optimisation activity pushed Suffield Gas production to the high end of our guidance range.

Organic Growth and Capital Projects

In Canada, IPC had originally set a limited capital budget for 2021. At the end of Q2 2021, IPC increased the capital expenditure budget to allow the 2021 execution of a five infill well project at the Onion Lake Thermal asset and an oil optimisation project at the Suffield asset.

At Onion Lake Thermal, new production sustaining Pad D' was brought online in Q3 2021. As of the end of Q4 2021, all six production wells have been successfully brought online with initial production in line with pre sanction expectations. During Q4 2021, the five well infill drilling campaign was successfully completed at Onion Lake Thermal. All five production wells have been brought online with positive initial indications as the wells clean up.

The production ramp up and testing of the third well pair at the Blackrod SAGD pilot project continued through Q4 2021. Heat conformance and production performance remain ahead of expectation.

MALAYSIA

Production in Mboepd	WI	Three months ended December 31		Year ended December 31	
		2021	2020	2021	2020
Bertam	100% [1]	4.5	4.2	4.4	4.4

[1] *100% from April 10, 2021 (75% previously)*

Production

Net production from the Bertam field on Block PM307 during Q4 2021 was ahead of CMD guidance at 4,500 boepd with continued excellent operational performance and facility uptime close to 100%.

Organic Growth and Capital Projects

In Malaysia, IPC originally set a limited capital budget for 2021. In April 2021, IPC increased its working interest in the Bertam field from 75% to 100%. At the end of Q2 2021, IPC increased the capital expenditure budget to allow for the planned 2021 execution of the A15 sidetrack well and the production well pump rate optimisation project.

At the end of Q4 2021, A15 sidetrack drilling operations have commenced with first oil from the well planned to be delivered in the first quarter of 2022. The production well pump rate optimisation project is scheduled to follow in Q1 2022.

FRANCE

Production in Mboepd	WI	Three months ended December 31 2021	Three months ended December 31 2020	Year ended December 31 2021	Year ended December 31 2020
France					
- Paris Basin	100%[1]	2.5	2.5	2.6	2.4
- Aquitaine	50%	0.4	0.4	0.4	0.4
		2.9	2.9	**3.0**	2.8

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

Production
Net production in France during Q4 2021 was ahead of CMD guidance at 2,900 boepd with stable production and good uptime at the major producing fields. In Q4 2021, strong reservoir performance continued at the Vert-la-Gravelle field supported by increased water injection.

Organic Growth
In France, IPC set a limited capital budget for 2021. IPC continues to mature future development projects in France, with drilling and optimisation opportunities ready for sanction at the discretion of the Group.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	2021	2020	2019
Revenue	**666,409**	324,164	553,749
Gross profit	**210,321**	(83,986)	152,904
Net result	**146,059**	(77,941)	103,588
Earnings per share – USD	**0.94**	(0.50)	0.63
Earnings per share fully diluted – USD	**0.92**	(0.49)	0.62
Operating cash flow[1]	**336,732**	119,423	307,944
Free cash flow[1]	**262,884**	9,342	89,308
EBITDA[1]	**330,754**	108,451	302,513
Net debt at period end[1]	**94,312**	321,193	231,503

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	December 31, 2021	December 31, 2020	December 31, 2019
Non-current assets	1,122,514	1,240,653	1,252,600
Current assets	151,160	92,467	112,041
Total assets	**1,273,674**	1,333,120	1,364,641
Total non-current liabilities	331,152	527,530	474,200
Current liabilities	94,979	97,137	99,632
Total liabilities	**426,131**	624,667	573,832
Net assets	**847,543**	708,453	790,809
Working capital (including cash)	**56,181**	(4,670)	12,409

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	2021	Q4-21	Q3-21	Q2-21	Q1-21	2020	Q4-20	Q3-20	Q2-20	Q1-20
Revenue	**666,409**	**215,296**	172,551	144,278	134,284	**324,164**	103,353	95,346	44,929	80,536
Gross profit	**210,321**	**79,469**	58,636	34,286	37,930	**(83,986)**	(60,570)	5,557	(16,537)	(12,436)
Net result	**146,059**	**66,918**	30,557	21,693	26,891	**(77,941)**	(45,250)	8,850	(1,472)	(40,069)
Earnings per share – USD	**0.94**	**0.43**	0.20	0.14	0.17	**(0.50)**	(0.29)	0.06	(0.01)	(0.25)
Earnings per share fully diluted – USD	**0.92**	**0.42**	0.19	0.14	0.17	**(0.49)**	(0.29)	0.06	(0.01)	(0.25)
Operating cash flow[1]	**336,732**	**110,687**	91,365	66,959	67,721	**119,423**	46,019	37,181	14,742	21,481
Free cash flow[1]	**262,884**	**86,960**	76,607	50,366	48,951	**9,342**	28,571	22,766	717	(42,712)
EBITDA[1]	**330,754**	**110,087**	89,223	65,181	66,263	**108,451**	43,004	34,251	12,187	19,009
Net debt at period end[1]	**94,312**	**94,312**	161,199	240,617	286,132	**321,193**	321,193	322,092	341,367	302,473

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

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

	Three months ended – December 31, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	84,039	53,940	47,166	18,863	–	**204,008**
NGLs	–	172	–	–	–	**172**
Gas	212	33,076	–	–	–	**33,288**
Net sales of oil and gas	**84,251**	**87,188**	**47,166**	**18,863**	–	**237,468**
Change in under/over lift position	–	–	–	2,958	–	**2,958**
Royalties	(7,968)	(7,095)	–	–	–	**(15,063)**
Hedging settlement	(7,109)	(3,323)	–	–	–	**(10,432)**
Other operating revenue	–	171	–	194	–	**365**
Revenue	**69,174**	**76,941**	**47,166**	**22,015**	–	**215,296**
Production costs (including inventory movements)	(36,585)	(34,998)	(19,984)	(10,994)	–	**(102,561)**
Depletion	(8,121)	(10,758)	(7,843)	(3,571)	–	**(30,293)**
Depreciation of other tangible fixed assets	–	–	(2,628)	–	–	**(2,628)**
Exploration and business development costs	(4)	–	–	–	(341)	**(345)**
Gross profit/(loss)	**24,464**	**31,185**	**16,711**	**7,450**	**(341)**	**79,469**

	Three months ended – December 31, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	31,835	28,352	18,569	10,333	–	89,089
NGLs	–	72	–	–	–	72
Gas	97	18,528	–	–	–	18,625
Net sales of oil and gas	31,932	46,952	18,569	10,333	–	107,786
Change in under/over lift position	–	–	–	2,430	–	2,430
Royalties	(2,954)	(2,596)	–	–	–	(5,550)
Hedging settlement	(1,867)	(3,866)	–	–	–	(5,733)
Other operating revenue	–	–	3,910	384	126	4,420
Revenue	27,111	40,490	22,479	13,147	126	103,353
Production costs (including inventory movements)	(16,589)	(24,106)	(8,803)	(7,724)	–	(57,222)
Depletion	(7,381)	(11,262)	(6,553)	(4,597)	–	(29,793)
Depreciation of other tangible fixed assets	–	–	(2,751)	–	–	(2,751)
Exploration and business development costs	(24)	–	(829)	(33)	(128)	(1,014)
Impairment costs of oil and gas properties	–	–	–	(73,143)	–	(73,143)
Gross profit/(loss)	3,117	5,122	3,543	(72,350)	(2)	(60,570)

	Year ended – December 31, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	268,403	190,287	100,436	75,949	–	635,075
NGLs	–	570	–	–	–	570
Gas	630	99,389	–	–	–	100,019
Net sales of oil and gas	**269,033**	**290,246**	**100,436**	**75,949**	–	**735,664**
Change in under/over lift position	–	–	–	5,391	–	5,391
Royalties	(25,179)	(21,245)	–	–	–	(46,424)
Hedging settlement	(22,272)	(11,320)	–	–	–	(33,592)
Other operating revenue	–	171	4,208	927	64	5,370
Revenue	**221,582**	**257,852**	**104,644**	**82,267**	**64**	**666,409**
Production costs (including inventory movements)	(131,700)	(128,016)	(25,243)	(40,048)	–	(325,007)
Depletion	(29,667)	(43,097)	(30,156)	(16,093)	–	(119,013)
Depreciation of other tangible fixed assets	–	–	(10,108)	–	–	(10,108)
Exploration and business development costs	(8)	–	(259)	(7)	(1,686)	(1,960)
Gross profit/(loss)	**60,207**	**86,739**	**38,878**	**26,119**	**(1,622)**	**210,321**

	Year ended – December 31, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	89,206	78,146	60,465	35,700	–	263,517
NGLs	–	214	–	–	–	214
Gas	334	59,616	–	–	–	59,950
Net sales of oil and gas	89,540	137,976	60,465	35,700	–	323,681
Change in under/over lift position	–	–	–	(630)	–	(630)
Royalties	(8,202)	(5,862)	–	–	–	(14,064)
Hedging settlement	1,351	(3,334)	–	–	–	(1,983)
Other operating revenue	–	–	15,555	1,164	441	17,160
Revenue	82,689	128,780	76,020	36,234	441	324,164
Production costs (including inventory movements)	(64,623)	(88,759)	(24,793)	(26,453)	–	(204,628)
Depletion	(26,255)	(40,555)	(27,759)	(17,327)	–	(111,896)
Depreciation of other tangible fixed assets	–	–	(11,681)	–	–	(11,681)
Exploration and business development costs	(3,011)	–	(741)	(2,389)	(661)	(6,802)
Impairment costs of oil and gas properties	–	–	–	(73,143)	–	(73,143)
Gross profit/(loss)	(11,200)	(534)	11,046	(83,078)	(220)	(83,986)

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

Three months and year ended December 31, 2021, Review

Revenue

Total revenue amounted to USD 215,296 thousand for Q4 2021 compared to USD 103,353 thousand for Q4 2020 and USD 666,409 thousand for the year ended December 31, 2021, compared to USD 324,164 thousand for the year ended December 31, 2020, and is analyzed as follows:

	Three months ended December 31		Year ended December 31	
USD Thousands	2021	2020	2021	2020
Crude oil sales	204,008	89,089	635,075	263,517
Gas and NGL sales	33,460	18,697	100,589	60,164
Change in under/overlift position	2,958	2,430	5,391	(630)
Royalties	(15,063)	(5,550)	(46,424)	(14,064)
Hedging settlement	(10,432)	(5,733)	(33,592)	(1,983)
Other operating revenue	365	4,420	5,370	17,160
Total revenue	**215,296**	103,353	**666,409**	324,164

The main components of total revenue for the three months and year ended December 31, 2021, and December 31, 2020, respectively are detailed below.

Crude oil sales

	Three months ended – December 31, 2021				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Total
Crude oil sales					
- Revenue in USD thousands	84,039	53,940	47,166	18,863	**204,008**
- Quantity sold in bbls	1,405,654	873,890	577,258	235,921	**3,092,723**
- Average price realized USD per bbl	59.79	61.72	81.71	79.96	**65.96**

	Three months ended – December 31, 2020				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Total
Crude oil sales					
- Revenue in USD thousands	31,835	28,352	18,569	10,333	**89,089**
- Quantity sold in bbls	1,113,135	860,551	395,244	225,974	**2,594,904**
- Average price realized USD per bbl	28.60	32.95	46.98	45.73	**34.33**

Crude oil revenue was more than double for Q4 2021 compared to Q4 2020 mainly due to higher oil prices. Q4 2020 was impacted by the global Covid-19 outbreak causing a decrease in oil demand and prices.

The Suffield area assets and part of the Onion Lake 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. 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 Q4 2021, WTI averaged USD 77 per bbl compared to USD 43 per bbl for Q4 2020 and the average discount to WCS used in our pricing formula was USD 15 per bbl (USD 9 per bbl for Q4 2020).

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There were two cargo liftings in Malaysia during Q4 2021 compared to two cargo liftings in Q4 2020. Produced unsold oil barrels from Bertam at the end of Q4 2021 amounted to 103,000 barrels, see Change in Inventory Position section below. There was no Aquitaine cargo lifted in Q4 2021. The average Dated Brent crude oil price was USD 80 per bbl for Q4 2021 compared to USD 44 per bbl for the comparative period.

USD Thousands	Year ended – December 31, 2021 Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Total
Crude oil sales					
- Revenue in USD thousands	268,403	190,287	100,436	75,949	**635,075**
- Quantity sold in bbls	5,118,726	3,505,698	1,337,346	1,069,276	**11,031,046**
- Average price realized USD per bbl	52.44	54.28	75.10	71.03	**57.57**

USD Thousands	Year ended – December 31, 2020 Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Total
Crude oil sales					
- Revenue in USD thousands	89,206	78,146	60,465	35,700	**263,517**
- Quantity sold in bbls	4,000,485	2,821,549	1,358,097	998,700	**9,178,831**
- Average price realized USD per bbl	22.30	27.70	44.52	35.75	**28.71**

Crude oil sales revenues were 141% higher for the year ended December 31, 2021, compared to the year ended December 31, 2020, mainly due to a 101% increase in achieved oil prices resulting from the improvement of market conditions as well as IPC's increased production.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. WTI averaged USD 68 per bbl and the average discount from WTI to WCS was approximately USD 13 per bbl for the year ended December 31, 2021, compared to an average WTI of USD 40 per bbl and an average discount from WTI to WCS of USD 13 per bbl for the comparative period in 2020.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 71 per bbl for the year ended December 31, 2021, compared to USD 42 per bbl for the comparative period in 2020.

Gas and NGL sales

	Three months ended – December 31, 2021 Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	33,248	212	**33,460**
- Quantity sold in Mcf	8,536,894	69,643	**8,606,537**
- Average price realized USD per Mcf	3.89	3.05	**3.89**

	Three months ended – December 31, 2020 Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	18,600	97	**18,697**
- Quantity sold in Mcf	8,922,304	54,072	**8,976,376**
- Average price realized USD per Mcf	2.08	1.79	**2.08**

Gas and NGL sales revenue was 79% higher for Q4 2021 compared to Q4 2020 mainly due to the higher achieved gas price. Approximately 98% of the Suffield gas production was physically sold on the Alberta/Saskatchewan border with the remainder being delivered in Alberta based on AECO pricing plus a premium. For Q4 2021, IPC realized an average price of CAD 4.87 per Mcf compared to AECO average pricing of CAD 4.66 per Mcf and Empress average pricing of CAD 4.99 per Mcf for Q4 2021.

	Year ended – December 31, 2021		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	99,959	630	**100,589**
- Quantity sold in Mcf	33,731,280	237,489	**33,968,769**
- Average price realized USD per Mcf	2.96	2.65	**2.96**

	Year ended – December 31, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	59,830	334	**60,164**
- Quantity sold in Mcf	35,113,522	224,252	**35,337,774**
- Average price realized USD per Mcf	1.70	1.49	**1.70**

Gas and NGL sales revenue was 67% higher for the year ended December 31, 2021, compared to the comparative period in 2020 mainly due to the higher achieved gas price. For the year ended December 31, 2021, IPC realized an average price of CAD 3.70 per Mcf compared CAD 2.28 per Mcf for the comparative period in 2020. The AECO average pricing was CAD 3.63 per Mcf and the Empress average pricing was CAD 3.90 per Mcf for 2021.

Hedging settlement

IPC enters into risk management contracts in order to ensure a certain level of cashflow. It focuses mainly on oil price swaps and collars to limit pricing exposure. IPC also uses natural gas at the Onion Lake Thermal project and the Blackrod SAGD pilot project to generate steam and manages the pricing risk by entering into fixed price swaps. The oil and gas pricing contracts are not entered into for speculative purposes.

The realized hedging settlements for Q4 2021 amounted to a loss of USD 10,432 thousand and for the year ended December 31, 2021, amounted to a loss of USD 33,592 thousand, consisting of USD 5,410 thousand on the gas contracts and USD 28,182 thousand on the oil contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Other operating revenue

Other operating revenue amounted to USD 365 thousand for Q4 2021 compared to USD 4,420 thousand for Q4 2020 and USD 5,370 thousand for the year ended December 31, 2021, compared to USD 17,160 thousand for the year ended December 31, 2020. Other operating revenue consists of lease fee income, tariff income and fees for strategic storage of inventory in France. The significant part of other operating revenue was third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia until April 10, 2021. Following the withdrawal of Petronas Carigali Sdn Bhd from the Production Sharing Contract for the Bertam Field, and its interest being assigned to IPC, there is no such third party lease fee income after April 10, 2021. From this date, 100% of the lease income is eliminated from other operating revenue and the corresponding self-to-self lease fee is eliminated from operating costs, and IPC reports additional oil sales revenues associated with the assigned 25% working interest in the Bertam field.

Production costs

Production costs including inventory movements amounted to USD 102,561 thousand for Q4 2021 compared to USD 57,222 thousand for Q4 2020 and USD 325,007 thousand for the year ended December 31, 2021, compared to USD 204,628 thousand for the year ended December 31, 2020, and is analyzed as follows:

	Three months ended – December 31, 2021					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	27,412	20,956	10,104	10,610	(4,140)	64,942
USD/boe[2]	11.89	15.90	24.27	39.37	n/a	15.07
Cost of blending	6,884	15,439	–	–	–	22,323
Change in inventory position	702	190	14,020	384	–	15,296
Production costs	34,998	36,585	24,124	10,994	(4,140)	102,561

	Three months ended – December 31, 2020					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	20,367	14,176	18,621	7,597	(11,730)	49,031
USD/boe[2]	8.60	12.71	48.62	28.70	n/a	11.87
Cost of blending	3,106	3,677	–	–	–	6,783
Change in inventory position	62	(693)	1,912	127	–	1,408
Production costs	24,106	16,589	20,533	7,724	(11,730)	57,222

	Year ended – December 31, 2021					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	102,084	79,213	51,420	39,852	(24,340)	248,229
USD/boe[2]	11.11	16.74	32.13	36.57	n/a	14.95
Cost of blending	25,579	52,855	–	–	–	78,434
Change in inventory position	353	(368)	(1,837)	196	–	(1,656)
Production costs	128,016	131,700	49,583	40,048	(24,340)	325,007

	Year ended – December 31, 2020					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	75,054	57,616	72,152	25,639	(46,665)	183,796
USD/boe[2]	8.48	14.69	44.47	25.14	n/a	11.92
Cost of blending	13,334	7,357	–	–	–	20,691
Change in inventory position	371	(350)	(694)	814	–	141
Production costs	88,759	64,623	71,458	26,453	(46,665)	204,628

[1] *See definition on page 21 under "Non-IFRS measures".*
[2] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period.*
[3] *Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating cost per boe for Malaysia to USD 14.33 and USD 17.99 for Q4 2021 and Q4 2020, respectively, and USD 16.92 and USD 15.71 for the year ended December 31, 2021, and the year ended December 31, 2020, respectively.*

Operating costs
Operating costs amounted to USD 64,942 thousand for Q4 2021 compared to USD 49,031 thousand for Q4 2020 and USD 248,229 thousand for the year ended December 31, 2021, compared to USD 183,796 thousand for the year ended December 31, 2020. The increase in costs in 2021 compared to 2020 is due to increased activity and higher energy costs. Operating costs per boe amounted to USD 15.07 per boe in Q4 2021 compared with USD 11.87 per boe in Q4 2020 and to USD 14.95 per boe for the full year 2021 which was below CMD guidance of USD 15.5 per boe mainly as a result of higher production volumes.

Cost of blending
For the Suffield area assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. Since July 2020, a portion of Onion Lake oil production is also blended and exported by pipeline. The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 22,323 thousand for Q4 2021 compared to USD 6,783 thousand for Q4 2020 and USD 78,434 thousand for the year ended December 31, 2021, compared to USD 20,691 thousand for the year ended December 31, 2020. The increase is attributable to larger Onion Lake blending volumes and higher diluent prices in line with higher oil prices.

As a result of the blending, actual sales volumes are higher than produced barrels. A net gain of USD 214 thousand and a gain of USD 11 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q4 2021 and Q4 2020 respectively. A gain of USD 421 thousand and a cost of USD 1,258 thousand were recognized for the year ended December 31, 2021, and December 31, 2020, respectively.

Change in inventory position
The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion, and market value, and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. At the end of year 2021, IPC had crude entitlement of 103,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold).

Depletion and decommissioning costs
The total depletion and decommissioning costs amounted to USD 30,293 thousand for Q4 2021 compared to USD 29,793 thousand for Q4 2020 and USD 119,013 thousand for the year ended December 31, 2021, compared to USD 111,896 thousand for the year ended December 31, 2020. The depletion charge is analyzed in the following tables:

	Three months ended – December 31, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,758	8,121	7,843	3,571	**30,293**
USD per boe	4.67	6.16	18.84	13.25	**7.03**

	Three months ended – December 31, 2020				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	11,262	7,381	6,553	4,597	**29,793**
USD per boe	4.76	6.62	17.11	17.37	**7.21**

	Year ended – December 31, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	43,097	29,667	30,156	16,093	**119,013**
USD per boe	4.69	6.27	18.84	14.77	**7.17**

	Year ended – December 31, 2020				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	40,555	26,255	27,759	17,327	**111,896**
USD per boe	4.58	6.70	17.11	16.99	**7.26**

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 USD 2,628 thousand for Q4 2021 compared to USD 2,751 thousand for Q4 2020 and USD 10,108 thousand for the year ended December 31, 2021, compared to USD 11,681 thousand for the year ended December 31, 2020. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis based on the Bertam field 2P reserves.

Exploration and business development costs
The total exploration and business developments costs amounted to USD 345 thousand for Q4 2021 and USD 1,960 thousand for the year ended December 31, 2021. These costs mainly related to business development costs.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 12,364 thousand for the year ended December 31, 2021, compared to USD 12,788 thousand for the year ended December 31, 2020.

Net financial items
Net financial items amounted to a charge of USD 30,214 thousand for the year ended December 31, 2021, compared to a charge of USD 14,987 thousand for the year ended December 31, 2020, and included a non-cash net foreign exchange loss of USD 1,994 thousand for 2021 compared to a net foreign exchange gain of USD 13,028 thousand for 2020. The foreign exchange movements mainly result from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 28,220 thousand for the year ended December 31, 2021, compared to USD 28,015 thousand for the year ended December 31, 2020.

The interest expense amounted to USD 12,867 thousand for the year ended December 31, 2021, compared to interest expense USD 13,401 thousand for the comparative period in 2020. Despite the lower borrowings, the cost of financing remained at similar level as 2020 following the refinancing of the credit facilities during 2020.

The unwinding of the asset retirement obligation discount rate amounted to USD 11,488 thousand for the year ended December 31, 2021, compared to USD 10,837 thousand for year ended December 31, 2020.

Income tax
The corporate income tax amounted to a charge of USD 21,684 thousand for the year ended December 31, 2021, compared to a credit of USD 33,820 thousand for the year ended December 31, 2020. The income tax movements in 2021 mainly relate to deferred taxes with low cash taxes reflected. No corporate income tax is payable in Canada and Malaysia in 2021 due to the historical tax pools.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the year ended December 31, 2021, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	14,805	18,645	10,333	2,451	**46,234**
Exploration and evaluation	–	(2,723)	472	7	**(2,244)**
	14,805	15,922	10,805	2,458	**43,990**

Capital expenditure of USD 43,990 thousand was mainly in Canada including completion of the Pad D' project and start of the infill drilling program on the Onion Lake Thermal field, additional field optimisation activities and commencement of the drillling in Malaysia.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 46,363 thousand as at December 31, 2021, which included USD 43,649 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis based on the Bertam field 2P reserves.

Financial Position and Liquidity

Financing
As at January 1, 2020, the Group had a reserve-based lending credit facility of USD 175 million (the "International RBL") with a maturity to end of June 2022 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had a reserve-based lending credit facility of CAD 375 million (the "Canadian RBL") with a maturity date in May 2021, in connection with its oil and gas assets in Canada.

In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France (the "France Facility") under a financial assistance program instituted by the French government. In April 2021, IPC extended the France Facility until May 2026, with quarterly repayments commencing in August 2022. The France Facility amount was fully drawn as at December 31, 2021, and as at February 8, 2022.

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

In March 2020, in connection with the completion of the acquisition of Granite Oil Corp. ("Granite"), the Group assumed the bank debt of Granite consisting of a revolving credit facility of CAD 42.5 million (the "Granite Facility"). In July 2020, the Group amended and extended the Canadian RBL to a facility size of CAD 350 million with a maturity extended until the end of May 2022. In December 2020, the Granite Facility was amended to a CAD 30 million revolving credit facility.

In June 2021, the Group consolidated the amounts outstanding under the Granite Facility into the Canadian RBL and the Granite Facility was terminated. As of June 30, 2021, the Canadian RBL was amended to a facility size of CAD 300 million with a maturity extended until the end of May 2023. Under the Canadian RBL, the Group was required, and satisfied the requirement, to hedge 40% of forecast Canadian oil production from June 30, 2021, to December 31, 2021. There are currently no mandatory hedging requirements beyond the end of 2021.

The borrowing base availability under the International RBL was agreed in November 2021 at approximately USD 100 million of which USD 4 million was drawn as at December 31, 2021. The borrowing base availability under the Canadian RBL was CAD 300 million of which CAD 120 million was drawn as at December 31, 2021.

Total net debt as at December 31, 2021 amounted to USD 94 million.

The amounts drawn under the International RBL and the Canadian RBL as at December 31, 2021, are classified as non-current as there are no mandatory repayments within the next twelve months.

In February 2022, IPC completed the issuance of USD 300 million of senior unsecured bonds (the "Bonds"), which mature in February 2027 and have a fixed coupon rate of 7.25 percent per annum, payable in semi-annual instalments. The Group used a portion of the proceeds of the Bonds to fully repay the Canadian RBL and the International RBL, which were then cancelled. At the same time, the Group entered into a revolving credit facility of CAD 75 million (the "Canadian RCF") in connection with its oil and gas assets in Canada. The Canadian RCF has a maturity of February 2024.

An amount of USD 1.8 million drawn under the France Facility as at December 31, 2021 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the financing facilities as at December 31, 2021.

Cash and cash equivalents held amounted to USD 18.8 million as at December 31, 2021. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital
As at December 31, 2021, the Group had a net working capital balance including cash of USD 56,181 thousand compared to USD (4,670) thousand as at December 31, 2020. The difference as at December 31, 2021, from December 31, 2020, is mainly a result of higher trade receivables due to the higher oil price, the higher cash balances held and the reclassification of borrowings to long term following the refinancing in Canada, partly offet by the higher trade payables.

Non-IFRS Measures

In addition to using financial measures prescribed under IFRS, references are made in this MD&A to "operating cash flow", "free cash flow", "EBITDA", "operating costs" and "net debt", which are non-IFRS measures. Non-IFRS measures do not have any standardized meaning prescribed by IFRS and 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 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, administration and depreciation expenses before depreciation and less cash financial items. Free cash flow is used to analyze the amount of cash that is being generated by the business and that is available for such purposes as repaying debt, funding acquisitions and returning capital to shareholders.

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

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

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

Reconciliation of Non-IFRS Measures

Operating cash flow

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

	Three months ended December 31		Year ended December 31	
USD Thousands	2021	2020	2021	2020
Revenue	215,296	103,353	666,409	324,164
Production costs	(102,561)	(57,222)	(325,007)	(204,628)
Current tax	(2,048)	(112)	(4,670)	(113)
Operating cash flow	**110,687**	46,019	**336,732**	119,423

Free cash flow

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

	Three months ended December 31		Year ended December 31	
USD Thousands	2021	2020	2021	2020
Operating cash flow - see above	110,687	46,019	336,732	119,423
Capital expenditures	(17,441)	(7,732)	(43,990)	(77,659)
Abandonment and farm-in expenditures[1]	(1,282)	(2,109)	(4,546)	(6,138)
General, administration and depreciation expenses before depreciation[2]	(2,648)	(3,127)	(10,648)	(11,085)
Cash financial items[3]	(2,356)	(4,480)	(14,664)	(15,199)
Free cash flow	**86,960**	28,571	**262,884**	9,342

[1] *See note 20 to the financial statements*

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

[3] *See notes 5 and 6 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 December 31		Year ended December 31	
USD Thousands	2021	2020	2021	2020
Net result	66,918	(45,250)	146,059	(77,941)
Net financial items	4,079	(6,731)	30,214	14,987
Income tax	5,408	(12,139)	21,684	(33,820)
Depletion	30,293	29,793	119,013	111,896
Depreciation of other tangible fixed assets	2,628	2,751	10,108	11,681
Impairment	–	73,143	–	73,143
Exploration and business development costs	345	1,014	1,960	6,802
Depreciation included in general, administration and depreciation expenses[1]	416	423	1,716	1,703
EBITDA	**110,087**	43,004	**330,754**	108,451

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

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

	Three months ended December 31		Year ended December 31	
USD Thousands	2021	2020	2021	2020
Production costs	102,561	57,222	325,007	204,628
Cost of blending[1]	(22,323)	(6,783)	(78,434)	(20,691)
Change in inventory position	(15,296)	(1,408)	1,656	(141)
Operating costs	**64,942**	49,031	**248,229**	183,796

[1] *Item is shown in the Financial Statements. See production costs section above*

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

USD Thousands	December 31, 2021	December 31, 2020
Bank loans	113,122	327,691
Cash and cash equivalents	(18,810)	(6,498)
Net debt	**94,312**	321,193

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued two letters of credit as follows: (a) CAD 2.6 million in respect of its obligations to purchase diluent; and (b) CAD 600,000 in respect of its obligations related to the Ferguson asset, increasing by CAD 100,000 annually to a maximum of CAD 1,000,000.

Outstanding Share Data

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

As at January 1, 2020, the total number of common shares issued and outstanding in IPC was 159,790,869. In 2020, IPC repurchased 4,448,112 common shares under a share repurchase program and all of these shares were cancelled. IPC suspended further share repurchases under the program which expired in early November 2020. As at December 31, 2020, IPC had a total of 155,342,757 common shares issued and outstanding.

Following the exercise of stock options during February 2021, the number of issued and outstanding common shares of the Corporation increased by 25,000 to 155,367,757 common shares. On December 1, 2021, IPC announced the commencement of a share repurchase program. During the period up to December 31, 2021, IPC repurchased an aggregate of 1,330,303 common shares. A number of 169,652 shares were cancelled at December 31, 2021. The remaining 1,160,651 shares have been cancelled in January 2022. As at December 31, 2021, IPC had a total of 155,198,105 common shares issued and outstanding with voting rights.

As at February 8, 2022, following the cancellation of a further 726,676 common shares repurchased, IPC has a total of 153,310,778 common shares issued and outstanding with no par value.

Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 40,697,533 common shares in IPC, representing 26.5% of the outstanding common shares as at February 8, 2022.

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 5,279,308 IPC Share Unit Plan awards (992,491 awards granted in July 2019, 10,703 awards granted in January 2020, 1,421,515 awards granted in March 2020, 25,335 awards granted in July 2020, 45,781 awards granted in January 2021, 1,036,773 awards granted in March 2021, 1,716,000 awards granted in May 2021, 18,167 awards granted in July 2021 and 12,543 awards granted in January 2022) outstanding as at February 8, 2022.

Contractual Obligations and Commitments

In Canada, an oil pipeline from the Onion Lake Thermal field to the Husky Alberta Gathering System has been built by Husky Midstream ("Husky") for the exclusive use of IPC. Onion Lake Thermal oil production is blended with condensate before being transported via the pipeline and is therefore expected to attract improved realised prices as a result of the blended oil. The pipeline is also expected to improve the reliability and uptime of the transportation and production at Onion Lake Thermal. The initial investment in the pipeline was met by Husky and is to be recovered through an agreed tariff charged to IPC. IPC has committed to a firm transportation service for 15 years from commencement of service, with total tariffs committed as shown in the table below:

	2022[1]	2023	2024	2025	2026	Thereafter
Transportation service (MCAD)	22.5	27.3	28.0	28.4	29.0	300.9

[1] *Assuming commissioning of the pipeline and commencement of the service occurs during the first quarter of 2022.*

The initial tariffs escalate at 2% per annum and approximately 65% of the forecast cost for 2022 is reflected in the 2022 Capital Markets Day (CMD) guidance of operating costs of USD 15.2/boe which is in line with the actual 2021 operating costs of USD 15.0/boe. The remaining 35% of the forecast cost for 2022 is also reflected in the CMD cost of blending guidance.

In Malaysia, IPC has an obligation to make payments towards historic costs on Block PM307 payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves has been provided for in the Group's Balance Sheet – see Note 21 Provisions of the Financial Statements.

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

Lundin Energy has charged the Group USD 636 thousand in respect of office space rental and USD 1,508 thousand in respect of shared services provided during the year 2021.

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

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at December 31, 2021, the Corporation had entered into oil and gas price hedges – see below.

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

Capital Management

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

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

Price of Oil and Gas

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

Based on analysis of the circumstances, the management assesses the benefits of forward hedging monthly sales contracts for the purpose of protecting cash flow. If management believes that a hedging contract will appropriately help manage cash flow then it may choose to enter into a commodity price hedge. In addition, see the Financial Position and Liquidity section above regarding applicable credit facility covenants to hedge future production.

The Group had gas price sale financial hedges outstanding as at December 31, 2021, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
January 1, 2022 – March 31, 2022	20,000	AECO Swap	CAD 4.15/GJ
April 1, 2022 – September 30, 2022	20,000	AECO Swap	CAD 3.14/GJ

The Group had no oil price sale financial hedges outstanding as at December 31, 2021.

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

These hedges had a net fair value of USD 1,159 thousand at December 31, 2021.

Currency Risk

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

Interest Rate Risk

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

Credit Risk

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

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

RISK AND UNCERTAINTIES

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

See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resource Advisory" in this MD&A.

Pandemic: The Covid-19 virus and the restrictions and disruptions related to it had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. There can be no assurance that these effects will not continue or that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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

Non Financial Risks

Exploration, Development and Production Risks: Oil and gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Group depends on its ability to find, acquire, develop and commercially produce oil and gas reserves. Without the continual addition of new reserves, any existing reserves associated with the Group's oil and gas assets at any particular time, and the production therefrom, will decline over time as such existing reserves are exploited. There is a risk that additional commercial quantities of oil and gas will not be discovered or acquired by the Group. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Future oil and gas development may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.

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

Volatility in Oil and Gas Commodity Prices and Price Differentials: The marketability and price of oil and gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and gas may depend upon its ability to access space on pipelines that deliver oil and gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in Europe, Asia, the United States, Canada and elsewhere, the actions of OPEC and OPEC+, governmental regulation, political instability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports, the availability of alternative fuel sources and the potential for increased supply of oil and gas for unconventional shale oil and shale gas and other services.

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

The Group's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials in Canada between the Group's heavy crude oil (in particular the heavy crude oil differential) and quoted market prices. The market price for heavy crude oil and bitumen in Canada is generally lower than market prices for light oil, due principally to the higher costs associated with refining a barrel of heavy crude oil and higher transportation costs (diluent is required to be purchased and blended with heavy crude oil to transport on most pipelines). Heavy crude oil differentials are also influenced by other factors such as capacity and interruptions, refining demand and the quality of the oil produced, all of which are beyond the Group's control. It is difficult to predict future price differentials and any increase in heavy crude oil differentials could have an adverse effect on the Group's business, financial condition, results of operations and cash flows.

In order to transport crude oil production in Canada to sales markets, the Group is required to meet certain pipeline specifications. Heavy crude oil and bitumen is usually blended with a lighter hydrocarbon (commonly referred to as diluent) to increase its flow characteristics. The cost of diluent is generally correlated to crude oil prices. A shortfall in the supply of diluent may cause its price to increase which would adversely affect the Group's financial position and cash flow.

Climate Change: Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, or floods, or long-term shifts in climate patterns with sustained higher temperatures or sea level rise. These physical risks may have financial and operational implications for the Corporation, such as direct damage to assets and indirect impacts from supply chain disruption.

Reputational risks arise from the surge of societal pressure on the fossil fuel industry in relation to its contribution to global greenhouse gas (GHG) emissions. Maintaining a positive reputation in the eyes of investors, regulators, communities, employees and the general public is an important aspect for the success of the Corporation. Negative impact on the industry and the Corporation's reputation could result in the long term delays in obtaining regulatory approvals, increased operating costs, lower shareholder confidence, or availability of insurance and financing.

Regulatory climate change related risks arise from increased environmental regulation. A breach of such regulations may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. Furthermore, management of the Corporation believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity. There is a risk that any such programs, laws or regulations, if proposed and enacted, may contain emission reduction targets which will require substantial capital investments to adapt processes in place or lead to financial penalties or charges as a result of the failure to meet such targets.

The Group's facilities and operations, and the oil and gas that the Group markets, result in the emission of GHGs which makes the Group subject to GHG emissions legislation and regulation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Implementation of strategies by any level of government within the countries in which the Corporation operates, and whether to meet international agreed limits, or as otherwise determined, for reducing GHGs could have a material impact on the operations and financial condition of the Corporation.

In addition, concerns about climate change and public discussion that climate change may be associated with extreme weather conditions have resulted in a number of environmental activists and members of the public opposing the continued exploitation, transportation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on the Group and its operations and financial condition.

Emission and carbon tax regulations in Canada federally and regionally are evolving and as these regulations are established or amended, they may have an impact on organizations involved in heavy oil production. As a signatory to the United Nations Framework Convention on Climate Change and a party to the Paris Agreement, the Government of Canada committed to a 30% reduction in GHG emissions below 2005 levels by 2030; one of the policies announced to date by the Government of Canada to reduce GHG emission is the implementation of a nation-wide price on carbon emissions. It is difficult to assess the overall impact these regulations will have on the Group at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on the Group's business.

Operational Risks Relating to Facilities and Pipelines: The pipelines and facilities associated with the Group's assets, including the FPSO Bertam, are exposed to operational risks that can lead to hydrocarbon releases, production interruptions and unplanned outages. Other operating risks relating to the facilities and pipelines associated with the Group's assets include: the breakdown or failure of equipment; issues and failures affecting the FPSO Bertam; breakdown or malicious attacks on information systems or processes; the performance of equipment at levels below those originally intended; operator error; disputes and other issues with interconnected facilities; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares. The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

The Group's financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality construction standards and supply chain disruptions. Electricity, chemicals, supplies, abandonment, reclamation and labour costs are examples of operating costs that are susceptible to significant fluctuations. Fluctuations in operating and capital costs could negatively impact the Group's business, financial condition, results of operations, cash flows and value of it oil and gas reserves.

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

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

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves". This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material. See also "Reserves and Resource Advisory" below.

SAGD Recovery Process: The Group has implemented a SAGD recovery process at the Onion Lake Thermal project and would use the SAGD process at the Blackrod project. The SAGD recovery process requires a significant amount of gas or other fuels to produce steam for use in the recovery process. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the reservoir can impact the timing, cost and levels of production using this technology. There can be no assurance that the Group's operations will produce at the expected levels or on schedule. In addition, a significant amount of water is used in SAGD operations. Government regulations apply to access to and use of water. Any shortages in water supplies could lead to increased costs and have a material adverse effect on results of operation and financial condition.

Regulatory Approvals and Compliance and Changes in Legislation and the Regulatory Environment: Oil and gas operations (including exploration, development, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to exploration, production and abandonment activities, price, taxes, royalties and the exportation of oil and gas. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for crude oil and gas and increase the costs associated with the Group's oil and gas assets, any of which may have a material adverse effect on the business, financial condition, results of operations and prospects of the Group's oil and gas assets. In order to conduct oil and gas operations, the Group will require regulatory permits, licences, registrations, approvals, authorizations and concessions from various governmental authorities. There is a risk that the permits, licences, registrations, approvals, authorizations and concessions currently granted to the Group (including, for example, the Malaysian flagging status for the FPSO Bertam) will not be renewed or that the Group will be unable to obtain all of the permits, licences, registrations, approvals, authorizations and concessions that may be required to conduct operations that it may wish to undertake.

The French government has enacted legislation to cease granting new petroleum exploration licences in France and to restrict the production of oil and gas under existing production licences in France from 2040. There is a risk that France could implement further legislative changes and that the licence regime in France could become more onerous. In Canada, the oil and gas regulatory authorities have implemented regulations regarding the ability to transfer leases, licences, permits, wells and facilities between parties. These authorities have increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

Aboriginal Land Claims in Canada: In Canada, aboriginal groups have filed claims in respect of their aboriginal and treaty rights against the federal and certain provincial governments as well as private individuals and companies. The Group is not aware of any claims made with respect to its properties or assets; however; if a claim arose and was successful, it may have a material adverse effect on the Group's business, financial condition, results of operation and prospects. The majority of the Group's interests at Onion Lake are situated on traditional reserve lands and are subject to the federal rules and regulations of Indian Oil and Gas Canada as well as of the Onion Lake Cree Nation of Saskatchewan/Alberta. There are risks associated with the management of the Group's interests on these lands, including access and lease terms.

Change of Control under Licences: Certain of the licence areas associated with the Group's oil and gas assets, including in France and in Canada, require government consent or compliance with regulations imposed by oil and gas regulatory authorities to effect a change of control of the owner or an assignment of the ownership interest in the licence area. There may also be contractual restrictions on assignment and change of control, including in the Suffield area of Canada where certain operations are conducted within a Canadian Forces Base under access agreements with Canadian federal government and the Alberta provincial government. Accordingly, should the ownership interest in these licence areas be reduced or if there is a change of control of the Corporation, consent may be required in order to remain in compliance with the applicable licences and concessions. The failure to obtain such consent may have a material adverse effect on the Corporation. Further, the requirement to obtain such consent may limit the ability of a third party to effect a change of control transaction with the Corporation.

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

Reliance on Third-Party Operators: The Group has partners in many of the licence, lease and PSC areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France, the Group is not the operator of the licence and concession areas and must depend on the competence, expertise, judgment and financial resources (in addition to those of its own and, where relevant, other partnership and joint venture companies) of the partner operator and the operator's compliance with the terms of the licences, leases, PSCs and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may adversely affect third-party operators which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.

Reliance on Third-Party Infrastructure: The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, most of which it does not own. The amount of oil and gas that the Group is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities (for example, Total is ceasing crude oil transportation and storage operations at the Grandpuits refinery in the Paris Basin, France), could ceased refining and result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production or increased operating or transportation costs. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Group's business financial condition, results of operations, cash flows and future prospects. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may adversely affect third-party infrastructure which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.

Credit Facilities and Bonds: The Group is, and may in the future become, party to credit facilities with international financial institutions. The Corporation has also issued bonds and may issue further bonds in the future. The terms of these facilities and bonds may contain operating and financial covenants and restrictions on the ability of the Group to, among other things, incur or lend additional debt, pay dividends and make restricted payments, encumber its assets, sell assets and enter into certain merger or consolidation transactions. The failure of the Group to comply with the covenants contained in these facilities and bonds could result in an event of default, which could, through acceleration of debt, enforcement of security or otherwise, materially and adversely affect the operating results and financial condition of the Group.

In addition, the maximum amount that the Group is permitted to borrow under its credit facilities may be subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the credit facilities, the Group may be required to repay all or a portion of the amounts owing thereunder.

If the Group fails to comply with the covenants in these facilities and bonds, is unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of the Group's assets by the creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards the Group's debt would the remainder, if any, be available for the benefit of shareholders.

Credit Ratings: Credit ratings affect the Corporation's ability to obtain short term and long term financing and the cost of such financing. A reduction in the current rating or a negative change in the rating outlook could adversely affect the cost of financing and access to sources of liquidity and capital. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

Competition for Resources and Markets: The international petroleum industry is competitive in all its phases. The Group competes with numerous other organizations in the search for, and the acquisition of, oil and gas properties and in the marketing of oil and gas. The Corporation's competitors include oil and gas companies that may have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves and resources in the future depends not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory and development drilling. Competitive factors in the distribution and marketing of oil and gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources and renewable energies.

Marketing: A decline in the Group's ability to market oil and gas production could have a material adverse effect on its production levels or on the price that the Group receives for production, which in turn may affect the financial condition of the Corporation and the market price of the Common Shares. IPC's business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities (for example, the Total-operated Grandpuits facility which ceased refining and is ceasing crude oil transportation and storage operations) as well as, potentially, rail loading facilities and railcars. Applicable regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect IPC's ability to produce and market oil and gas. If market factors change and inhibit the marketing of production, overall production or realized prices may decline, which may affect the financial condition of the Corporation and the market price of the Common Shares.

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

Fraud, Bribery and Corruption: The operations relating to the Group's oil and gas assets are governed by the laws of many jurisdictions, which generally prohibit bribery and other forms of corruption. While the Corporation has implemented an anti-corruption compliance program across the Group, the Corporation cannot guarantee that the Group's employees, officers, directors, agents, or business partners have not in the past or will not in the future engage in conduct undetected by the processes and procedures to be adopted by the Corporation and for which the Corporation might be held liable under applicable anti-corruption laws. Despite the Corporation's compliance program and other related training initiatives, it is possible that the Corporation, or some of its subsidiaries, employees or contractors, could be subject to an investigation related to charges of bribery or corruption as a result of the unauthorized actions of its employees or contractors, which could result in significant corporate disruption, onerous penalties and reputational damage.

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

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

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

Expiration and Renewal of Licences, Leases and Production Sharing Contracts: Certain properties constituting the Group's oil and gas assets are held in the form of licences, leases and production sharing contracts (PSCs). If the holder of the licence, lease or PSC or the operator of the licence, lease or PSC fails to meet the specific requirement of a licence, lease or PSC, including compliance with environmental, health and safety requirements, the licence, lease or PSC may terminate or expire. There is a risk that the obligations required to maintain each licence, lease or PSC will not be met. The termination or expiration of the licence, lease or PSC, or the working interests relating to a licence may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group's oil and gas assets. From time to time, the licences and leases may, in accordance with their terms, become due for renewal; there is a risk that these licences, leases and PSCs associated with the Group's oil and gas assets will not be renewed by the relevant government authorities, on terms that will be acceptable to the Corporation. There also can be significant delay in obtaining licence renewals which may already affect the operations associated with the Group's oil and gas assets.

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

Economic and Political Developments in Countries in which the Group Operates: International operations are subject to political, economic and other uncertainties. The Group's assets could also be adversely affected by changes in applicable laws and policies of Canada, Malaysia and France (including relating to the Covid-19 virus), which could have a negative impact on the Group.

In response to the Covid-19 virus, there are public health restrictions and other related disruptions which could have adverse effects on the business and operations of the Corporation, including production delays or interruptions. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of the Common Shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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

Information Security: The Group is dependent on its information systems and computer based programs. Failure, malfunction or security breaches by computer hackers and cyberterrorists of any such systems or programs may have a material adverse effect on the Group's business and systems, potentially affecting network assets and people's privacy. The Group manages cyber security risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The primary risks to the Group include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage.

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

Significant Shareholder: Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust (the "Trust Entities"), own approximately 26 percent of the aggregate voting shares of the Corporation. The Trust Entities' holdings may allow them to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as the Trust Entities maintain a significant interest in the Corporation, it is likely that the Trust Entities will exercise significant influence on the ability of the Corporation to, among other things, amend the articles of the Corporation, enter into a change in control transaction of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of the Trust Entities will not be aligned with the interests of other shareholders.

Financial Risks

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

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

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

Additional Funding Requirements: The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's funds from operations is not sufficient to satisfy its capital expenditure requirements, there is a risk that debt or equity financing will be unavailable to meet these requirements or, if available, will be on terms unacceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects and also negatively impact the market price of the Common Shares.

Variations in Foreign Exchange Rates and Interest Rates: World oil and gas prices are quoted in United States dollars and are therefore affected by exchange rates, which will fluctuate over time. Future exchange rates could accordingly impact the future value of the Corporation's reserves and resources as determined by independent evaluators. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there will be a credit risk associated with counterparties of the Corporation. An increase in interest rates could result in a significant increase in the amount the Corporation pays to service any debt that it may incur, which could negatively impact the market price of the Common Shares.

Issuance of Further Debt: From time to time, the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may create debt or increase the Corporation's then-existing debt levels above industry standards for oil and gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favorable terms. The level of the indebtedness that the Corporation may have from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Common Share Price Volatility: The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Corporation's control, including the following:

- Actual or anticipated fluctuations in the Corporation's results of operations;
- Recommendations by securities research analysts;
- Changes in the economic performance or market valuations of other companies that investors deem comparable to the Corporation;
- The loss of executive officers and other key personnel of the Corporation;
- Sales or perceived sales of additional Common Shares;
- Significant acquisitions or business combinations, strategic partnerships, joint ventures or capital;
- Commitments by or involving the Corporation or its competitors; and
- Trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Corporation's business segments or target markets.

Financial markets can experience significant price and volume fluctuations that may particularly affect the market prices of equity securities of companies and that may be unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three and twelve month periods ended December 31, 2021, 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).

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.

The Covid-19 virus and the restrictions and disruptions related to it had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. Although demand, commodity prices and share prices have recovered, there can be no assurance that these effects will not resume or that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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

Forward-looking statements include, but are not limited to, statements with respect to:
- IPC's ability to maximize liquidity and financial flexibility in connection with the current and any future Covid-19 outbreaks;
- The potential for an improved economic environment resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2022 production range, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to continue to react to recent events and navigate the Corporation through periods of volatile commodity prices;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's ability to maintain operations, production and business in light of the current and any future Covid-19 outbreaks and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third-party operators and infrastructure;
- IPC's intention and ability to continue to implement our strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Future development potential of the Suffield and Ferguson operations in Canada, including the timing and success of future oil and gas drilling and optimization programs;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, breakeven oil prices and net present values;
- Current and future drilling pad production and timing and success of facility upgrades, tie-in work and infill drilling at Onion Lake Thermal;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The timing and success of the future development projects and other organic growth opportunities in France;
- The ability to maintain current and forecast production in France;
- The ability of IPC to achieve and maintain current and forecast production in Malaysia;
- The success of the drilling of the A15 sidetrack well and of the production well pump rate optimisation project in Malaysia;
- The ability to IPC to acquire further common shares under the share repurchase program, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the share repurchase program;
- The ability of IPC to implement further shareholder distributions in addition to the share repurchase program;
- IPC's ability to implement its GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's ability to identify and complete future acquisitions; and
- Future drilling and other exploration and development activities.

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

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

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

These include, but are not limited to:
- The risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- The uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Health, safety and environmental risks;
- Commodity price fluctuations;
- Interest rate and exchange rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental risks;
- Competition;
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and abandonment regulations.

Readers are cautioned that the foregoing list of factors is not exhaustive. See also "Risk and Uncertainties"

Estimated free cash flow generation is based on IPC's current business plans over the period of 2022 to 2026. Assumptions include average net production of approximately 47 Mboepd, average Brent oil prices of USD 65 to 95 per boe escalating by 2% per year, average gas prices of CAD 3.00 per thousand cubic feet, and average Brent to Western Canadian Select differentials as estimated by IPC's independent reserves evaluator and as further described in the MCR. 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 material change report dated February 8, 2022 (MCR), the Corporation's Annual Information Form (AIF) for the year ended December 31, 2020, (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk and Uncertainties") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND 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 are effective as of December 31, 2021, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2021 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2021, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2020 price forecasts.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in the MCR. These price forecasts are as at December 31, 2021 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 270 MMboe as at December 31, 2021, by the mid-point of the 2022 CMD production guidance of 46,000 to 48,000 boepd.

The product types comprising the 2P reserves described in this MD&A are contained in the AIF. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil reserves/resources disclosed in this MD&A include solution gas and other by-products.

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

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

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

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

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

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

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

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated by IPC. 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 reserve and resources evaluations will be attained and variances could be material.

The reserves and resources information and data provided in this MD&A presents only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the Corporation's Annual Information Form for the year ended December 31, 2021, which will be filed on SEDAR (accessible at www.sedar.com) on or before April 1, 2022. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of net present value and other relevant information related to the contingent resources disclosed, is disclosed in the MCR available under IPC's profile on www.sedar.com and on IPC's website at www.international-petroleum.com.

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

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

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 (Mboepd)	Light and Medium Crude Oil (Mboepd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
December 31, 2021	21.7	8.5	100.2 MMcf (16.7 Mboe)	46.8
December 31, 2020	19.2	8.2	104.4 MMcf (17.4 Mboe)	44.9
Year ended				
December 31, 2021	20.4	8.4	99.9 MMcf (16.7 Mboe)	45.5
December 31, 2020	16.5	8.5	103.1 MMcf (17.2 Mboe)	42.1

This document also makes reference to IPC's forecast total average daily production of 46,000 to 48,000 boepd for 2022. IPC estimates that approximately 46% of that production will be comprised of heavy oil, approximately 21% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

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

Oil related terms and measurements

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

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

DIRECTORS

C. Ashley Heppenstall
Director, Chairman
London, England

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

Chris Bruijnzeels
Director
Abcoude, The Netherlands

Donald K. Charter
Director
Toronto, Ontario, Canada

Torstein Sanness
Director
Oslo, Norway

Emily Moore
Director
Toronto, Ontario, Canada

Lukas (Harry) H. Lundin
Director
Toronto, Ontario, Canada

OFFICERS

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

William Lundin
Chief Operating Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel and Corporate Secretary
Geneva, Switzerland

Chris Hogue
Senior Vice President Canada
Calgary, Alberta, Canada

Ryan Adair
Vice President Asset Management and
Corporate Planning Canada
Calgary, Alberta, Canada

INVESTOR RELATIONS

Rebecca Gordon
VP Corporate Planning and Investor Relations
Geneva, Switzerland

Sophia Shane
Vancouver, British Columbia, Canada

CORPORATE OFFICE

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

OPERATIONS OFFICE

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

REGISTERED AND RECORDS OFFICE

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

INDEPENDENT AUDITORS

PricewaterhouseCoopers SA, Switzerland

TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta, and Toronto, Ontario

MEDIA RELATIONS

Robert Eriksson
Stockholm, Sweden

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and NASDAQ Stockholm
Trading Symbol: IPCO

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

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