PAREX RESOURCES

FINANCIAL STATEMENTS

FOR THE YEAR ENDED **DECEMBER 31, 2025**

PAREXRESOURCES.COM | TSX | PXT

MANAGEMENT'S REPORT

Management is responsible for the reliability and integrity of the consolidated financial statements, the notes to the consolidated financial statements, and other financial information presented elsewhere in this annual report.

The consolidated financial statements were prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS Accounting Standards). Since a precise determination of many assets and liabilities is dependent on future events, the timely preparation of financial statements requires that management make estimates and assumptions and use judgment. When alternative accounting methods exist, management has chosen those that it deems most appropriate in the circumstances.

PricewaterhouseCoopers LLP were appointed by the Company's shareholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures as they considered necessary to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

The Board of Directors is responsible for overseeing that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Finance & Audit Committee. The Finance & Audit Committee recommends appointment of the external auditors to the Board, evaluates their independence and approves their fees. The Finance & Audit Committee meets regularly with management and the external auditors to oversee that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board for approval. The external auditors have full and unrestricted access to the Finance & Audit Committee to discuss their audit and their findings.

"signed"	"signed"
Imad Mohsen	Cameron Grainger
President and Chief Executive Officer	Chief Financial Officer

March 3, 2026

Independent auditor's report

To the Shareholders of Parex Resources Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Parex Resources Inc. and its subsidiaries (together, the Company) as at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS Accounting Standards).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2025 and 2024;
- the consolidated statements of comprehensive income for the years then ended;
- the consolidated statements of changes in equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, comprising material accounting policy information and other explanatory information.

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 Company 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.

PricewaterhouseCoopers LLP
Suncor Energy Centre, 111 5th Avenue South West, Suite 2900
Calgary, Alberta, Canada T2P 5L3
T.: +1 403 509 7500, F.: +1 403 781 1825
Fax to mail: ca_calgary_main_fax@pwc.com

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2025. 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.

Key audit matter	How our audit addressed the key audit matter
Impact of oil and natural gas reserves on net property, plant and equipment (PP&E) Refer to note 2 – Basis of preparation, significant accounting estimates and judgments, note 3 – Summary of material accounting policies, and note 9 – Property, plant and equipment to the consolidated financial statements. The Company had $1,500.2 million of net PP&E as at December 31, 2025. Depletion, depreciation and amortization (DD&A) expense was $200.4 million for the year then ended. PP&E within each cash generating unit (CGU) is depleted using the unit-of-production method based on proved plus probable reserves incorporating estimated future prices and costs. Costs subject to depletion include estimated forecast costs to be incurred in developing proved plus probable reserves. The proved plus probable reserves are prepared by the Company's independent qualified reserve evaluators (management's experts). Key assumptions used by management to determine the proved plus probable reserves include production forecasts, future commodity prices, future development and future production costs. We considered this a key audit matter due to (i) the judgments made by management, including the use of management's experts, when estimating the proved plus probable reserves; and (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures relating to the assumptions.	Our approach to addressing the matter included the following procedures, among others: • Tested how management determined the proved plus probable reserves used to determine the DD&A expense which included the following: – The work of management's experts was used in performing the procedures to evaluate the reasonableness of the proved plus probable reserves. As a basis for using this work, the competence, capabilities and objectivity of management's experts was evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's experts, tests of the data used by management's experts and evaluation of their findings for certain properties. – Evaluated the reasonableness of assumptions used, including production forecasts, future development costs, and future production costs by considering current and past performance of the Company and whether those assumptions were consistent with evidence obtained in other areas of the audit for certain properties, as applicable. – Evaluated the reasonableness of future commodity price estimates by comparing those forecasts with third party industry forecasts. • Recalculated the unit-of-production rates used to calculate the DD&A expense.

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 Accounting Standards, 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 Company'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 Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company'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 Company'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 Company'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 Company 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.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the consolidated financial statements. We are responsible for the direction, supervision and review of the audit work performed for purposes 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.

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.

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.

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

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta
March 3, 2026

CONSOLIDATED FINANCIAL STATEMENTS
Consolidated Balance Sheets

As at (thousands of United States dollars)	NOTE	December 31, 2025	December 31, 2024
ASSETS			
Current assets			
Cash and cash equivalents	24	$ 58,328	$ 98,022
Restricted cash and cash equivalents	24	5,424	581
Accounts receivable	5	78,329	82,686
Prepaids and other current assets		13,357	29,042
Marketable securities	7	45,090	—
Derivative financial instruments	27	776	—
Current income tax receivable	22	68,363	33,595
Crude oil inventory	6	4,327	2,017
		273,994	245,943
Exploration and evaluation	8	161,125	116,928
Property, plant and equipment	9	1,500,213	1,419,301
Long-term inventory	10	175,426	199,474
Other long-term assets		14,629	11,489
Deferred tax asset	22	142,253	88,475
Goodwill	14	73,452	73,452
		$ 2,341,092	$ 2,155,062
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		$ 235,809	$ 170,731
Derivative financial instruments	27	—	1,160
Current portion of decommissioning and environmental liabilities	19	10,158	14,655
		245,967	186,546
Bank debt	12	33,000	60,000
Lease obligations	13	7,814	4,622
Cash settled share-based compensation liabilities	18	15,228	9,553
Decommissioning and environmental liabilities	19	79,007	63,020
Other long-term liabilities		7,143	—
		388,159	323,741
Shareholders' equity			
Share capital	20	621,062	632,899
Contributed surplus		20,738	20,024
Retained earnings		1,311,133	1,178,398
		1,952,933	1,831,321
		$ 2,341,092	$ 2,155,062

Commitments and Contingencies (note 29)
Subsequent Events (note 31)
See accompanying Notes to the Consolidated Financial Statements

Approved by the Board:

"signed"   "signed"

Sigmund Cornelius, Director

Bob MacDougall, Director

Consolidated Statements of Comprehensive Income

For the year ended December 31, (thousands of United States dollars, except per share amounts)	NOTE	2025	2024
Oil and natural gas sales	**15**	**$ 1,005,842**	$ 1,280,029
Royalties		**(126,752)**	(201,418)
Net revenue		**879,090**	1,078,611
Other revenue	**15**	**9,826**	8,157
Commodity risk management contracts (loss)	**27**	**(1,419)**	(1,160)
Revenue		**887,497**	1,085,608
Expenses			
Production		**225,543**	255,278
Transportation		**76,444**	65,745
Purchased oil		**162**	904
General and administrative		**71,326**	68,908
Impairment of exploration and evaluation assets	**8**	**11,140**	54,085
Impairment of property, plant and equipment assets	**9**	**—**	78,417
Impairment of long-term inventory	**10**	**6,470**	10,000
Equity settled share-based compensation expense	**20**	**714**	878
Cash settled share-based compensation expense	**21**	**29,802**	584
Depletion, depreciation and amortization	**9**	**200,405**	215,770
Other expense	**16**	**29,200**	6,227
Foreign exchange (gain) loss	**27**	**(10,932)**	5,447
Unrealized gain on marketable securities	**7**	**(4,616)**	—
		635,658	762,243
Finance (income)	**17**	**(4,369)**	(4,315)
Finance expense	**17**	**21,402**	18,408
Net finance expense		**17,033**	14,093
Income before income taxes		**234,806**	309,272
Income tax (recovery) expense			
Current tax expense	**22**	**33,502**	90,389
Deferred tax (recovery) expense	**22**	**(53,779)**	158,203
		(20,277)	248,592
Net income and comprehensive income for the year		**$ 255,083**	$ 60,680
Basic net income per common share	**23**	**$ 2.62**	$ 0.60
Diluted net income per common share	**23**	**$ 2.62**	$ 0.60

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statements of Changes in Equity

For the year ended December 31, (thousands of United States dollars)		**2025**		2024
Share Capital				
Balance, beginning of year	**$**	**632,899**	$	660,817
Issuance of common shares under equity-settled plan		**—**		411
Repurchase of shares		**(11,837)**		(28,329)
Balance, end of year	**$**	**621,062**	$	632,899
Contributed Surplus				
Balance, beginning of year	**$**	**20,024**	$	19,248
Share-based compensation		**714**		878
Options exercised		**—**		(102)
Balance, end of year	**$**	**20,738**	$	20,024
Retained earnings				
Balance, beginning of year	**$**	**1,178,398**	$	1,275,362
Net income for the year		**255,083**		60,680
Repurchase of shares		**(14,677)**		(45,460)
Dividends		**(107,671)**		(112,184)
Balance, end of year		**1,311,133**		1,178,398
	$	**1,952,933**	$	1,831,321

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the year ended December 31, (thousands of United States dollars)	NOTE	2025	2024
Operating activities			
Net income		**$ 255,083**	$ 60,680
Add (deduct) non-cash items			
Depletion, depreciation and amortization	**9**	**200,405**	215,770
Non-cash finance expense	**17**	**12,511**	9,273
Non-cash other expense	**16**	**9,272**	3,580
Equity settled share-based compensation expense	**20**	**714**	878
Cash settled share-based compensation expense	**21**	**29,802**	584
Deferred tax (recovery) expense	**22**	**(53,779)**	158,203
Impairment of exploration and evaluation assets	**8**	**11,140**	54,085
Impairment of property, plant and equipment assets	**9**	**—**	78,417
Impairment of long-term inventory	**10**	**6,470**	10,000
Unrealized foreign exchange (gain) loss	**27**	**(10,857)**	29,603
Unrealized (gain) loss on commodity risk management contracts	**27**	**(1,160)**	1,160
Unrealized gain on marketable securities	**7**	**(4,616)**	—
Net change in assets and liabilities	**24**	**(30,229)**	(52,318)
Cash provided by operating activities		**424,756**	569,915
Investing activities			
Property, plant and equipment expenditures	**9**	**(200,595)**	(221,250)
Exploration and evaluation expenditures	**8**	**(109,730)**	(126,445)
Long-term inventory expenditures, net of transfers and sales	**10**	**17,578**	(4,773)
Property acquisition	**11**	**(15,968)**	—
Marketable securities	**7**	**(40,473)**	—
Net change in non-cash working capital	**24**	**45,150**	(39,775)
Cash (used in) investing activities		**(304,038)**	(392,243)
Financing activities			
Common shares repurchased	**20**	**(26,514)**	(73,789)
Dividends	**20**	**(107,671)**	(112,184)
Bank debt repayment	**12**	**(27,000)**	(30,000)
Issuance of common shares under equity-settled plans	**20**	**—**	309
Payments on lease obligation	**13**	**(752)**	(681)
Net change in non-cash working capital	**24**	**(932)**	1,449
Cash (used in) financing activities		**(162,869)**	(214,896)
Decrease in cash and cash equivalents and restricted cash and cash equivalents for the year		**(42,151)**	(37,224)
Impact of foreign exchange on foreign currency-denominated cash balances		**4,307**	(4,897)
Cash and cash equivalents and restricted cash and cash equivalents, beginning of year	**24**	**101,787**	143,908
Cash and cash equivalents and restricted cash and cash equivalents, end of year	**24**	**$ 63,943**	$ 101,787

Supplemental Disclosure of Cash Flow Information (note 24)
See accompanying Notes to the Consolidated Financial Statements

1. Corporate Information

Parex Resources Inc. and its subsidiaries ("Parex" or "the Company") are in the business of the exploration, development, production and marketing of oil and natural gas in Colombia.

Parex Resources Inc. is a publicly traded Company, incorporated and domiciled in Canada. Its registered office is at 2400, 525-8th Avenue S.W., Calgary, Alberta T2P 1G1. The Company was incorporated on August 17, 2009, pursuant to the Business Corporations Act (Alberta).

The consolidated financial statements were approved by the Board of Directors on March 3, 2026.

2. Basis of Preparation, Significant Accounting Estimates and Judgements

a) Statement of compliance

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

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 3, 2026, the date the Board of Directors approved the consolidated financial statements.

b) Basis of measurement

The consolidated financial statements have been prepared under the historical cost convention except for derivative financial instruments and share-based compensation transactions which are measured at fair value. The methods used to measure fair values are discussed in note 4 - Determination of Fair Values.

c) Use of management estimates, judgments and measurement uncertainty

The timely preparation of the consolidated financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the consolidated financial statements. Accordingly, actual results could differ from estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below:

(i) Depletion, depreciation and reserves

Depletion is based on the proved plus probable reserves as evaluated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and incorporating the estimated future cost of developing and extracting those. The proved plus probable reserves are prepared by the Company's independent qualified reserve evaluators. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates are based on production forecasts, future commodity prices, future development costs and future production costs. As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions of reserve estimates are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to determine that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative. Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion and are also used in measuring fair value less costs of disposal of property, plant and equipment for impairment calculations (see note 9 - Property, Plant and Equipment).

(ii) Determination of cash-generating units ("CGUs")
The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

(iii) Exploration and evaluation ("E&E")
The decision to transfer assets from E&E to property, plant and equipment ("PP&E") is primarily based on the estimated proved plus probable reserves used in the determination of an area's technical feasibility and commercial viability (see note 8 – Exploration and Evaluation Assets).

(iv) Decommissioning and environmental liabilities
Decommissioning and restoration costs will be incurred by the Company at the end of the operating life of certain of its assets. The ultimate decommissioning and restoration costs are uncertain, and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves, laws and regulations or their interpretation, the timing and likelihood of the settlement of the obligation, discount rates, and future interest rates. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The Company uses a risk-free discount rate based on forecasted Colombia interest rates.

Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed, and the associated costs can be estimated. These liabilities are in addition to the decommissioning liabilities due to government regulations that require the Company to perform additional mitigation against the environmental issues attributed to water usage and deforestation from oil and gas activities performed. In addition, the timing of expected settlement of the environmental liabilities differs from the timing of expected settlement of the decommissioning liabilities. Refer to note 19 – Decommissioning and Environmental Liabilities.

(v) Impairment indicators and discount rate
The recoverable amounts of CGUs and individual assets have been determined as the greater of either an asset's or CGU's value in use or fair value less costs of disposal. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, quantity of reserves and discount rates as well as future development and operating costs. It is reasonably possible that the commodity price assumptions may change, which may impact the estimated life of the oil and natural gas reserves and the recoverable economical reserves and may require a material adjustment to the carrying value of oil and natural gas assets. The Company monitors internal and external indicators of impairment relating to its property, plant and equipment, exploration and evaluation assets and long-term inventory. Refer to note 8 – Exploration and Evaluation Assets, note 9 – Property, Plant and Equipment, note 10 - Long-Term Inventory and note 14 – Goodwill.

(vi) Share-based compensation
Compensation costs accrued for under the Company's Stock Option plan are subject to the estimation of what the ultimate payout will be using the Black-Scholes pricing model which is based on significant assumptions such as the future volatility of the market price of Parex shares and expected term of the issued stock option. Compensation costs accrued for under the Company's Cash Settled Restricted Share Units ("CRSU") plan, Cash or share settled Restricted Share Units ("CosRSU") and Performance Share Units ("CosPSU") plan and Long Duration Restricted Share Units ("LDRSU") and Performance Share Units ("LDPSU") plan are measured at fair value using the Black-Scholes pricing model based on the market price of Parex shares on the date of issuance. Compensation costs accrued for under the Company's Deferred Share Unit ("DSU") plan are measured at fair value using the Black-Scholes pricing model based on the five-day weighted average share price at which the common shares of the Company traded for immediately preceding the date of issuance. Refer to note 20 - Share Capital and note 21 - Cash Settled Incentive Plans.

(vii) Derivative financial asset/liability
The estimated fair value of derivative instruments and resulting derivative assets and liabilities depends on estimated forward prices and volatility in those prices and by their nature are subject to measurement uncertainty.

(viii) Income taxes
Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty. The Company follows the liability method for calculating deferred taxes. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to the expectations of future cash flows from operations and the application of existing tax laws. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future.

Deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused temporary differences can be utilized. Future projected income and future tax rates could be affected by oil prices, quantities of oil and gas reserves, and future oil and gas production. If these factors or other circumstances change, the Company would reassess its ability to record any increase or decrease in its deferred income tax asset. To the extent that actual outcomes differ from management's estimates, taxation charges or credits may arise in future periods. Refer to note 22 - Income Tax.

(ix) Business combinations, corporate and property acquisitions

Business combinations, corporate and property acquisitions are accounted for using the acquisition method of accounting whereby the assets acquired, and the liabilities assumed are recorded at fair values. The determination of fair value often requires management to make assumptions and estimates about future events. The fair value of property, plant and equipment recognized in a business combination, corporate or property acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in PP&E) are estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The market value of E&E assets are estimated with reference to the market values of current arm's length transactions in comparable locations. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill (or gain from a bargain purchase) in the acquisition equation. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

3. Summary of Material Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements and have been applied consistently by the Company and its subsidiaries.

a) Consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries at December 31, 2025. The principal operating subsidiaries and their activities are:

Entity	Country of incorporation	Country of principle business activity	Ownership %	Principle business activity
Parex Resources (Colombia) AG	Switzerland	Colombia	100	Oil and natural gas exploration and development
Verano Energy (Switzerland) AG	Switzerland	Colombia	100	Oil and natural gas exploration and development

The above listing does not include the wholly owned holding company subsidiaries or inactive operating company subsidiaries of Parex. All companies in the Parex group are wholly owned subsidiaries.

Inter-company balances and transactions are eliminated on consolidation. Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. A significant portion of the Company's operating cash flows is derived through joint operations which are involved in the development and production of crude oil in Colombia. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

b) Foreign currency translation

(i) Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Company operates (the "functional currency"). The consolidated financial statements are presented in United States dollars, which is the functional currency of Parex.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the date of the transaction. Generally, foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in currencies other than an operation's functional currency are recognized in the statement of comprehensive income.

c) Financial instruments

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.

The Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Classification and Measurement of Financial Assets

The initial classification of a financial asset depends upon the Company's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which the Company classified its financial assets:

- Amortized Cost: Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows, and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest;
- Fair Value through Other Comprehensive Income ("FVOCI"): Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest; or
- Fair Value Through Profit or Loss ("FVTPL"): Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial instruments and investments.

On initial recognition, the Company may irrevocably designate a financial asset that meets the amortized cost or FVOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch. On initial recognition of an equity investment that is not held-for-trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in OCI. There is no subsequent reclassification of fair value changes to earnings following the derecognition of the investment. However, dividends that reflect a return on investment continue to be recognized in net earnings. This election is made on an investment-by-investment basis.

At initial recognition, the Company measures a financial asset at its fair value and, in the case of a financial asset not at FVTPL, including transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are recorded as an expense in net earnings.

Financial assets are reclassified subsequent to their initial recognition only if the business model for managing those financial assets changes. The affected financial assets will be reclassified on the first day of the first reporting period following the change in the business model. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Impairment of Financial Assets

The Company recognizes loss allowances for Expected Credit Losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component.

As at December 31, 2025, all of the Company's receivables were outstanding for less than 90 days. The average expected credit loss on the Company's trade accounts receivable was 0.5% at December 31, 2025.

Classification and Measurement of Financial Liabilities

A financial liability is initially classified as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable.

Financial liabilities at FVTPL are measured at fair value with changes in fair value, along with any interest expense, recognized in net earnings. Other financial liabilities are initially measured at fair value less directly attributable transaction costs and are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in net earnings. Any gain or loss on derecognition is also recognized in net earnings.

A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, it is treated as a derecognition of the original liability and the recognition of a new liability. When the terms of an existing financial liability are altered, but the changes are considered non-substantial, it is accounted for as a modification to the existing financial liability. Where a liability is substantially modified it is considered to be extinguished, and a gain or loss is recognized in net earnings based on the difference between the carrying amount of the liability derecognized and the fair value of the revised liability. Where a liability is modified in a non-substantial way, the amortized cost of the liability is remeasured based on the new cash flows and a gain or loss is recorded in net earnings.

Derivative Financial Instruments

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Risk management assets and liabilities are derivative financial instruments classified as measured at FVTPL. Derivatives financial instruments are recorded using mark-to-market accounting whereby instruments are recorded in the consolidated balance sheets as either an asset or liability with changes in fair value recognized in net earnings as a gain or loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

d) Capital assets

(i) Exploration and evaluation

All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. These costs include unproved property acquisition costs, exploration costs, geological and geophysical costs, decommissioning costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to comprehensive income as E&E expenses.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to PP&E, where they are depleted. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to comprehensive income as impairment of exploration and evaluation assets. Net proceeds from any disposal of an intangible exploration asset are recorded as a reduction in intangible assets.

(ii) Property, plant and equipment

All costs directly associated with the development of oil and natural gas reserves are capitalized on an area-by-area basis. Development costs include expenditures for areas where technical feasibility and commercial viability have been determined. These costs include proved property acquisitions, development drilling, completion of wells, gathering facilities and infrastructure, decommissioning and restoration costs and transfers of E&E assets.

Costs accumulated within each CGU are depleted using the unit-of-production method based on proved plus probable reserves incorporating estimated future prices and costs. Costs subject to depletion include estimated forecast costs to be incurred in developing proved plus probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

Costs associated with office furniture, fixtures and leasehold improvements are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 1 to 5 years.

(iii) Long-term inventory

All costs in the form of long-lead material and equipment inventory, such as drill casing, natural gas compressors, and other major equipment, are initially capitalized. As the assets are used, they are incorporated into the costs of the related E&E and PP&E projects.

e) Impairment of long-term assets

The carrying amounts of the Company’s long-term assets, other than deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment.

For the purpose of PP&E impairment testing, assets are grouped into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amounts of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal (“FVLCD”).

The value in use is determined by estimating the present value of the pre-tax future net cash flows expected to be derived from the continued use of the asset or CGU. The FVLCD is based on available market information, where applicable. In the absence of such information, FVLCD is determined using discounted future after tax net cash flows which are based on the following assumptions: proved plus probable reserves, production forecasts, future commodity prices, future development and operating costs, future production costs, and discount rates. The proved plus probable reserves, production forecasts, future commodity prices, future development costs and future production costs are prepared by the Company's independent qualified reserve evaluators. E&E assets are assessed for impairment when they are reclassified to PP&E, and, if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. E&E assets are allocated to related CGUs where they are assessed for impairment upon their eventual reclassification to PP&E.

E&E assets not reclassified to PP&E are assessed for impairment on an asset-by-asset basis.

Long-term inventory is assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

If an indication of impairment exists, management estimates the recoverable amount of the E&E assets or long-term inventory.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income.

The recoverable amount of goodwill is determined as the fair value less costs of disposal using a discounted cash flow method. Goodwill is evaluated at the Colombia segment level as business combinations giving rise to goodwill do not have specifically identifiable benefits to any one CGU.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

f) Crude oil inventory

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

g) Purchased oil

Purchased oil includes costs to buy third party oil. The costs for third party oil are initially recorded in inventory until the crude oil title is transferred.

h) Goodwill

Goodwill is recorded on a business acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized, and an impairment test is performed annually or as events occur that could indicate impairment. To test for impairment, goodwill is allocated to each of the Company's CGUs, groups of CGUs, or an operating segment expected to benefit from the acquisition. Goodwill is tested by combining the carrying amounts of property, plant and equipment, exploration and evaluation assets and goodwill and comparing this to the recoverable amount. Fair value less costs of disposal, is derived by estimating the discounted after-tax future net cash flows as described in the property, plant and equipment impairment test, plus the fair market value of undeveloped land, seismic and inventory. Value in use is assessed using the present value of the expected future cash flows. Any excess of the carrying amount over the recoverable amount is recorded as impairment. Impairment charges, which are not tax affected, are recognized in comprehensive income and are not reversed. Goodwill is reported at cost less any impairment.

i) Revenue recognition

Parex principally generates revenue from the sale of commodities, which include crude oil and natural gas. Revenue associated with the sale of commodities is recognized when control is transferred from Parex to its customers. The Company's commodity sale contracts represent a series of distinct transactions. The Company considers its performance obligations to be satisfied and control to be transferred when all the following conditions are satisfied:

- Parex has transferred title and physical possession of the commodity to the buyer;
- Parex has transferred the significant risks and rewards of ownership of the commodity to the buyer; and
- Parex has the present right to payment.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Company sells its production of crude oil and natural gas pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. The Company does not have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a result, Parex does not adjust its revenue transactions for the time value of money.

Parex enters into contracts with customers that can have performance obligations that are unsatisfied (or partially unsatisfied) at the reporting date. The Company applies a practical expedient of IFRS 15 and does not disclose information about remaining performance obligations that have original expected durations of one year or less, or for performance obligations where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance completed to date. The Company also applies a practical expedient of IFRS 15 that allows any incremental costs of obtaining contracts with customers to be recognized as an expense when incurred rather than being capitalized.

Contract modifications with the Company's customers could change the scope of the contract, the price of the contract, or both. A contract modification exists when the parties to the contract approve the modification either in writing, orally, or based on the parties' customary business practices. Contract modifications are accounted for either as a separate contract when there is an additional product at a stand-alone selling price, or as part of the existing contract, through either a cumulative catch-up adjustment or prospectively over the remaining term of the contract, depending on the nature of the modification and whether the remaining products are distinct.

The Company's revenue transactions do not contain significant financing components.

Parex generates other revenue from non-core activities including pipeline transportation revenue and revenue related to energy generation and use of infrastructure. Other revenue is recognized when it is probable that the economic benefits will flow to the entity, the amount can be measured reliably and is measured at the fair value of the consideration received or receivable.

j) Equity settled share-based compensation

The Company has an incentive stock option plan pursuant to which the Company may issue options for certain employees, officers and directors as described in note 20 - Share Capital. The Company records share-based compensation expense using the fair value method. The fair value of an option granted is calculated at the grant date using the Black-Scholes pricing model and expensed over the vesting period of the option. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised security. Any consideration received on the exercise of stock options is credited to share capital.

Upon the exercise of the options the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

k) Cash settled share-based compensation

The Company has a Cash Settled Restricted Share Unit ("CRSUs") plan which allows the Company to issue CRSUs to certain employees of Parex Colombia as described in note 21 - Cash Settled Incentive Plans. Obligations for payments of cash under the foreign subsidiaries' CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the CRSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture. The CRSUs liability cannot be settled by the issuance of common shares.

The Company has a Deferred Share Unit ("DSU") plan which allows the Company to issue DSUs to all non-employee directors of Parex Resources Inc., as described in note 21 - Cash Settled Incentive Plans. As DSUs vest immediately on issuance, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately on issuance based on the fair value of the DSUs. The fair value of DSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the DSUs result in a corresponding change in the recorded liability. The accrued compensation for a unit that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

The Company has a Cash or Share Settled Restricted Share Unit/Performance Share Unit ("CosRSU/CosPSU") incentive plan to issue CosRSUs and CosPSUs to certain employees of Parex Canada as described in note 21 - Cash Settled Incentive Plans. Obligations for payments of cash or settlement of shares under the CosRSUs and CosPSUs plan are accrued as compensation expense over the vesting period based on the fair value of the CosRSUs and CosPSUs. The fair value of CosRSUs and CosPSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the CosRSUs and CosPSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture. The CosRSUs and CosPSUs liability can be settled in cash or by the issuance of common shares at the election of the employee.

The Company has a Long Duration Restricted Share Unit/Performance Share Unit ("LDRSU/LDPSU") incentive plan to issue LDRSUs and LDPSUs to certain employees of Parex Canada as described in note 21 - Cash Settled Incentive Plans. Obligations for payments of cash or settlement of shares under the LDRSUs and LDPSUs plan are accrued as compensation expense over the vesting period based on the fair value of the LDRSUs and LDPSUs. The fair value of LDRSUs and LDPSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the LDRSUs and LDPSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture. The LDRSUs and LDPSUs liability can be settled in cash or by the issuance of common shares at the election of the employee.

l) Provisions
A provision is recognized if, as a result of a past event, the Company has a current legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

m) Decommissioning and environmental liabilities
The Company's activities give rise to dismantling, decommissioning, environmental, abandonment and site disturbance remediation activities. Provisions are made for the estimated cost of the future site restoration and capitalized in the relevant asset category.

Decommissioning and environmental liabilities are measured at the present value of management's best estimate of the cost and future timing of the expenditure required to settle the present obligation at the balance sheet date using a risk-free discount rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense whereas increases (decreases) due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning and environmental liabilities are charged against the provision to the extent the provision was established.

n) Operating Segments
Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by the Company's chief operating decision makers. The operating segments are Canada and Colombia. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow.

o) Finance income and expense
Finance expense comprises credit facility interest related to the drawn credit facility, standby fees related to the undrawn credit facility, bank taxes, accretion on provisions, other and expected credit loss provision (recovery). Finance income comprises interest earned on cash and other income.

p) Other expense
Other expense is comprised mainly of other Colombian taxes, legal provisions, Colombian tax credits purchased, loss (gain) on settlement of decommissioning liabilities and loss (gain) on settlement of tangible assets.

q) Cash and cash equivalents
Cash and cash equivalents is comprised of cash and other short-term highly liquid investments with maturities less than 3 months held in chartered banks in Canada and recognized financial institutions in Colombia and Switzerland with BBB+ credit ratings or higher.

r) Restricted cash and cash equivalents

Restricted cash and cash equivalents is comprised of cash and cash equivalents pledged to satisfy commitments in long term contracts. Restrictions will lapse when work obligations are satisfied pursuant to the contracts. Cash and claims to cash that are restricted as to withdrawal or use for other than current operations or are designated for expenditure to satisfy commitments pursuant to long-term contracts, are excluded from the current asset classification. The long-term portion of restricted cash and cash equivalents is included in other long-term assets on the Company's balance sheet.

s) Marketable securities

Marketable securities is comprised of investments in shares of public corporations.

t) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in comprehensive income.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred tax is recognized in respect of temporary differences arising between the tax basis of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred tax is determined on a non-discounted basis using tax rates, currency exchange rates and laws enacted or substantively enacted by the balance sheet date and expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred tax is not provided on temporary differences arising on investments in subsidiaries except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company, and it is probable that the temporary difference will not be reversed in the foreseeable future. Deferred tax assets and liabilities are presented as non-current.

u) Per share information

Basic net income per share is calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees, except when the effect would be anti-dilutive.

v) Leases

Right-of-use asset ("ROU asset") and a corresponding lease obligation are recognized on the balance sheets on the date that a lease asset becomes available for use. Interest associated with the lease obligation is recognized over the lease period with a corresponding increase in the underlying lease obligation. ROU assets are depreciated on a straight-line basis over the lease term. Depreciation on ROU assets is recognized in DD&A.

ROU assets and lease obligations are initially measured on a present value basis. Lease obligations are measured as the net present value of the lease payments which may include fixed lease payments, variable lease payments and payments to exercise an extension or termination option if applicable, if the Company is reasonably certain to exercise either of those options. ROU assets are measured at cost, which is composed of the amount of the initial measurement of the lease obligation, less any incentives received. The rate implicit in the lease is used to determine the present value of the liability and ROU asset arising from a lease, unless this rate is not readily determinable, in which case the Company's incremental borrowing rate is used.

ROU assets and lease obligations are remeasured when there is a change in the future lease payments arising from a change in an index or rate or term, or if there is a change in the assessment on whether the Company will exercise an extension or termination option.

Short-term leases and leases of low-value assets are not recognized on the balance sheets and lease payments are instead recognized in the financial statements as incurred.

w) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of common shares are recognized as a deduction from equity, net of any tax effects. When the company repurchases its own common shares, share capital is reduced by the average carrying value of the shares repurchased. The excess of the purchase price over the average carrying value is recognized as a deduction from Retained Earnings. Shares are cancelled upon repurchase.

x) Dividends

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are declared by the Board of Directors.

y) Future Accounting Pronouncements

The Company plans to adopt the following amendments to accounting standards, issued by the International Accounting Standards Board ("IASB"), that are effective for annual periods beginning on or after January 1, 2026. The pronouncements will be adopted on their respective effective dates.

i) Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures

In May 2024, the IASB issued amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* related to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The amendments will be effective January 1, 2026, but are not expected to have a material impact on Parex's consolidated financial statements.

ii) IFRS 18 Presentation and Disclosure in Financial Statements

In April 2024, the IASB issued IFRS 18 *Presentation and Disclosure in Financial Statements* ("IFRS 18") which will replace IAS 1 and includes requirements for all entities applying IFRS for the presentation and disclosure of information in the financial statements. IFRS 18 will introduce new totals, subtotals and categories for income and expenses in the statement of income, as well as requiring disclosure about management-defined performance measures ("MPMs") and additional requirements regarding the aggregation and disaggregation of certain information. The new guidance is expected to improve the usefulness of information presented and disclosed in the financial statements of companies. IFRS 18 will be effective for annual reporting periods beginning on or after January 1, 2027, with early adoption permitted, and it must be adopted on a retrospective basis.

Parex is currently assessing the impact of this new IFRS accounting standard on its consolidated financial statements. Throughout 2026, Parex will assess system changes, draft and finalize financial statements to quantify the impact of changes, MPMs and related disclosures ahead of the 2027 effective date.

4. Determination of Fair Values

A number of the Company’s accounting policies and disclosures require the determination of fair value for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the methods below. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

a) PP&E, exploration and evaluation and long-term inventory assets

The fair value of PP&E, exploration and evaluation, and long-term inventory assets are determined if there are indicators of impairment. The fair value of PP&E, exploration and evaluation, and long-term inventory assets is the estimated amount for which the assets could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s-length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas assets (included in PP&E) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on the reserve reports prepared by the Company's independent qualified reserve evaluators. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

b) Cash, accounts receivable and accounts payable and accrued liabilities

The fair value of cash, accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2025 and 2024 the fair value of these balances approximated their carrying value due to their short-term to maturity.

c) Marketable Securities

Marketable securities are initially recognized at fair value on the date the investment is made and are remeasured at fair value at each subsequent reporting date. The fair value of marketable securities on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair value is based on quoted market prices from active markets.

d) Stock options

The fair value of stock options is measured using the Black-Scholes pricing model. Measurement inputs include the share price on the measurement date, exercise price of the option, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general option-holder behavior), expected dividends, expected forfeiture rate and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 20 - Share Capital.

e) Cash settled restricted share units, cash or share settled restricted share units and performance share units, long duration restricted share units and performance share units and deferred share units

The fair value of CRSUs, CosRSUs and CosPSUs, LDRSUs and LDPSUs, and DSUs are measured using the Black-Scholes pricing model based on the market price of Parex shares on each balance sheet date. Refer to note 21 - Cash Settled Incentive Plans.

f) Derivative financial asset/liability

Risk management contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date. The fair value of the risk management contract on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair values are based on quoted market prices where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions.

5. Accounts Receivable

	December 31, 2025	December 31, 2024
Trade receivables	**$ 72,317**	$ 77,106
Value added taxes (VAT)	**6,012**	5,580
Total	**$ 78,329**	$ 82,686

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. VAT receivable is $6.0 million as at December 31, 2025 (December 31, 2024 - $5.6 million). All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Crude Oil Inventory

	December 31, 2025	December 31, 2024
Crude oil inventory	**$ 4,327**	$ 2,017

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location. During 2025, $611.5 million (year ended December 31, 2024 - $728.0 million) of produced crude oil inventory cost was expensed to the consolidated statements of comprehensive income. Purchased crude oil is sold immediately. The cost associated with purchased oil is shown in the consolidated statements of comprehensive income as purchased oil expense.

7. Marketable securities

	December 31, 2025	December 31, 2024
Marketable securities	**$ 45,090**	$ —

In 2025, the Company acquired 6,084,986 common shares of GeoPark Ltd (NYSE: GPRK), representing approximately 11.8% ownership, for aggregate consideration of $40.5 million ($6.65 per share). The fair value of these shares at December 31, 2025 was $45.1 million, resulting in an unrealized gain of $4.6 million, which is recorded in the consolidated statement of comprehensive income.

8. Exploration and Evaluation Assets

Cost		
Balance at December 31, 2023	**$**	**211,590**
Additions and transfers from long-term inventory		126,445
Transfers to PP&E		(168,053)
Changes in decommissioning and environmental liability		1,031
Exploration and evaluation impairment		(54,085)
Balance at December 31, 2024	**$**	**116,928**
Additions and transfers from long-term inventory		109,730
Transfers to PP&E		(60,020)
Changes in decommissioning and environmental liability		5,627
Exploration and evaluation impairment		(11,140)
Balance at December 31, 2025	**$**	**161,125**

Additions and Transfers

E&E assets consist of the Company's exploration projects which are pending either the determination of proved or probable reserves or impairment. During the year ended December 31, 2025, additions of $109.7 million (year ended December 31, 2024 - $126.4 million) represent the Company's share of costs incurred on E&E assets during the period. During the year ended December 31, 2025, $60.0 million of E&E assets were transferred to PP&E related to Block LLA-74 (year ended December 31, 2024 - $168.1 million transferred to PP&E related to the Arauca Block).

For the year ended December 31, 2025, $1.9 million of general and administrative costs (year ended December 31, 2024 - $3.6 million) have been capitalized in respect of exploration and evaluation activities during the current period.

2025 Impairments

During 2025, the Company completed impairment reviews of its E&E assets. It was determined that the carrying amount of certain E&E assets wouldn't be recovered, primarily associated with the LLA-94 Block for costs related to exploration wells which indicated non-economic results and has relinquished the block. It was determined that the impairment was $11.1 million which is recorded in the consolidated statements of comprehensive income for the year ended December 31, 2025.

2024 Impairments

During 2024, the Company completed impairment reviews of its E&E assets. It was determined that the carrying amount of certain E&E assets wouldn't be recovered, primarily associated with the LLA-122 Block for costs related to an exploration well which indicated technically unfeasible results at an acceptable risk tolerance. The impairment review compared the carrying value of the assets to the fair value less cost of disposal to determine the recoverable amount which was determined to be $nil for the LLA-122 block assets. It was determined that the impairment was $54.1 million which is recorded in the consolidated statements of comprehensive income for the year ended December 31, 2024.

The fair value less cost of disposal approach requires assumptions which are level 3 inputs.

At December 31, 2025 and December 31, 2024, the Company did not have any E&E assets in Canada.

9. Property, Plant and Equipment

		Canada		Colombia		Total
Cost						
Balance at December 31, 2023	**$**	**17,612**	**$**	**3,385,937**	**$**	**3,403,549**
Additions and transfers from long-term inventory		3,820		217,430		221,250
Transfers from E&E assets		—		168,053		168,053
Changes in decommissioning and environmental liability		—		(14,523)		(14,523)
Balance at December 31, 2024		**21,432**		**3,756,897**		**3,778,329**
Additions and transfers from long-term inventory		1,340		199,255		200,595
Additions related to property acquisition - Note 11		—		16,788		16,788
Right-of-use asset addition (non-cash)		—		4,338		4,338
Transfers from E&E assets		—		60,020		60,020
Changes in decommissioning and environmental liability		—		372		372
Balance at December 31, 2025	**$**	**22,772**	**$**	**4,037,670**	**$**	**4,060,442**
Accumulated Depreciation, Depletion and Amortization						
Balance at December 31, 2023	**$**	**9,778**	**$**	**2,055,596**	**$**	**2,065,374**
Depletion and depreciation for the year		1,975		212,961		214,936
Depreciation - Right-of-use asset		760		74		834
DD&A included in crude oil inventory costing		—		(533)		(533)
Property, plant and equipment impairment		—		78,417		78,417
Balance at December 31, 2024		**12,513**		**2,346,515**		**2,359,028**
Depletion and depreciation for the year		2,312		196,701		199,013
Depreciation - Right-of-use asset		740		652		1,392
DD&A included in crude oil inventory costing		—		796		796
Balance at December 31, 2025	**$**	**15,565**	**$**	**2,544,664**	**$**	**2,560,229**
Net book value:						
As at December 31, 2023	$	7,834	$	1,330,341	$	1,338,175
As at December 31, 2024	$	8,919	$	1,410,382	$	1,419,301
As at December 31, 2025	**$**	**7,207**	**$**	**1,493,006**	**$**	**1,500,213**

Additions and Transfers

During 2025, property, plant and equipment ("PPE") additions of $200.6 million mainly relate to drilling and facility costs in Colombia. During the year ended December 31, 2025, $60.0 million of E&E assets were transferred to PP&E related to Block LLA-74.

During 2024, additions of $221.3 million mainly related to drilling and facility costs in Colombia. During the year ended December 31, 2024, $168.1 million of E&E assets were transferred to PP&E related to the Arauca Block.

For the year ended December 31, 2025, future development costs of $345.3 million (year ended December 31, 2024 - $426.7 million) were included in the depletion calculation for development and production assets. For the year ended December 31, 2025, $8.9 million of general and administrative costs (year ended December 31, 2024 - $5.0 million) have been capitalized in respect of development and production activities during the current period.

Impairments

The carrying amounts of the Company's PP&E assets are reviewed at each reporting date to determine whether there is any indication of impairment.

2025

At December 31, 2025, there were no indicators of impairment noted or indicators requiring a reversal of previously recorded impairments.

2024

A revision of the estimation of the total proved and probable reserves in the Aguas Blancas CGU and the Boranda/Fortuna CGU, both in the Magdalena Basin, for the year ended December 31, 2024, evidenced a decline as compared to the prior year estimation. Management considered this to be an indicator of impairment and carried out an impairment review of these CGUs. For all other CGUs, at December 31, 2024, there were no indicators of impairment noted or indicators requiring a reversal of previously recorded impairments.

The Company determined that the carrying amount of the Aguas Blancas CGU and the Boranda/Fortuna CGU, both in the Magdalena Basin, exceeded their recoverable amounts and an impairment of $78.4 million was recorded in the consolidated statements of comprehensive income for the three-month period ended December 31, 2024. The recoverable amount was determined using fair value less cost of disposal. The fair value less cost of disposal approach requires assumptions which are level 3 inputs.

The fair value was determined using discounted future after tax net cash flows of proved plus probable reserves using forecast prices and costs prepared by the Company's independent qualified reserve evaluators at December 31, 2024. Refer to note 14 – Goodwill for the future crude oil prices used by Parex’s independent reserve evaluator. There are no E&E assets associated with these CGUs. Future cash flows were discounted using a rate of 14%. As at December 31, 2024, the recoverable amount of the Aguas Blancas CGU was estimated to be $20.9 million, and the recoverable amount of the Boranda/Fortuna CGU was estimated to be $3.5 million. A 1% change to the assumed discount rate or a 5% change in forward price estimates over the life of the reserves would have an immaterial impact on the impairment.

10. Long-term Inventory

The Company has long-lead material inventory such as drill casing, natural gas compressors, and other major equipment.

Cost		
Balance at December 31, 2023	**$**	**204,701**
Additions		55,990
Transfers to E&E and PP&E assets		(40,028)
Transfer to production costs		(5,269)
Sale of inventory		(5,920)
Impairment		(10,000)
Balance at December 31, 2024	**$**	**199,474**
Additions		10,441
Transfers to E&E and PP&E assets		(25,045)
Transfer to production costs		(1,787)
Sale of inventory		(1,187)
Impairment		(6,470)
Balance at December 31, 2025	**$**	**175,426**

For the year ended December 31, 2025, long-term inventory additions were $10.4 million (year ended December 31, 2024 - $56.0 million). During the year ended December 31, 2025, $25.0 million (year ended December 31, 2024 - $40.0 million) of long-term inventory were incorporated into the costs of E&E and PP&E projects and $1.8 million (year ended December 31, 2024 - $5.3 million) were incorporated into production costs. During the year ended December 31, 2025, $1.2 million (year ended December 31, 2024 - $5.9 million) of long-term inventory was sold to third parties.

During 2025, the Company completed an impairment review of its long-term inventory. It was determined that the carrying amount of certain long-term inventory assets was lower than its recoverable amount and an impairment of $6.5 million (year ended December 31, 2024 - $10.0 million) was recorded in the consolidated statements of comprehensive income for the year ended December 31, 2025.

11. Property Acquisition

On March 14, 2025, Parex, through a foreign subsidiary, acquired an additional 25% working interest in the Azogue field in the LLA-32 Block and 12.5% working interest in the remainder of the LLA-32 Block (the "LLA-32 Acquisition") resulting in 100% working interest in the Block for the Company. The Company paid total net consideration of $16.0 million.

The consolidated statement of comprehensive income includes results of operation of the LLA-32 Acquisition since the closing date of March 14, 2025. There were no transaction costs associated with the LLA-32 Acquisition.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed		
PP&E	$	16,788
Decommissioning liabilities		(820)
	$	15,968

Consideration for the acquisition		
Purchase price	$	19,000
Purchase price adjustments		(3,032)
Net consideration	$	15,968
Cash paid	$	14,970
Working capital adjustments		998
Total consideration paid	**$**	**15,968**

No working capital was included in the assets acquired.

The pro forma results for the year ended December 31, 2025 are shown below, as if the LLA-32 Acquisition had occurred on January 1, 2025. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	$	1,009,605
Net revenue less direct costs	$	580,120

The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. The consolidated statement of comprehensive income for the year ended December 31, 2025 includes $32.6 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the year ended December 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is $22.0 million. Net income for the year ended December 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is considered impracticable to calculate.

12. Bank Debt

	December 31, 2025	December 31, 2024
Bank debt	**$ 33,000**	$ 60,000

The Company has a senior secured credit facility with a syndicate of banks which at December 31, 2025 had a borrowing base of $240.0 million (December 31, 2024 - $240.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash or letter of credit needs as they arise. As at December 31, 2025, $33.0 million (December 31, 2024 - $60.0 million) was drawn on the credit facility. The undrawn capacity on the credit facility at December 31, 2025 was $207.0 million (December 31, 2024 - $180.0 million).

The credit facility bears interest and fees based in the following manner:
(i) advances on the revolving facility bear interest at rates per annum equal to U.S. Base Rate or SOFR plus applicable margins;
(ii) advances on the operating line bear interest at rates per annum equal to Canadian Prime Rate plus applicable margins; and
(iii) undrawn amounts bear a commitment fee.

The credit facility is secured by the Company's Colombian assets and has final maturity date of May 21, 2027. The next annual review is scheduled to occur in May 2026.

Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1, and other standard business operating covenants for each reporting period. The Company was in compliance with all covenants at December 31, 2025.

The following table lists the Company's key financial covenant at December 31, 2025:

Covenant Description		December 31, 2025
Total Funded Debt to Adjusted EBITDA	Maximum Ratio 3.50:1	**0.54**

At December 31, 2025, performance guarantees were in place with the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petróleos S.A. ("Ecopetrol") joint venture blocks related to the exploration work commitments on its Colombian concessions in the amount of $235.1 million (December 31, 2024 - $160.7 million). The guarantees have been provided in the form of letters of credit for varying terms that are mainly provided by select Latin American banks on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks (see note 29 - Commitments and Contingencies).

13. Lease Obligation

The Company has the following future commitments associated with its lease obligations:

	Canada	Colombia	Total
Balance at December 31, 2023	**$ 5,154**	**$ 1,316**	**$ 6,470**
Interest expense	38	151	189
Lease payments	(702)	(168)	(870)
Foreign exchange (gain)	(419)	(167)	(586)
Balance at December 31, 2024	**$ 4,071**	**$ 1,132**	**$ 5,203**
Additions	—	4,338	4,338
Interest expense	34	331	365
Lease payments	(586)	(531)	(1,117)
Foreign exchange loss	159	197	356
Balance at December 31, 2025	**$ 3,678**	**$ 5,467**	**$ 9,145**
Current obligation	(733)	(598)	(1,331)
Long-term obligation	**$ 2,945**	**$ 4,869**	**$ 7,814**

During the year ended December 31, 2025, the Company recorded an addition of $4.3 million in Colombia for the lease of polymer injection equipment.

14. Goodwill

		December 31, 2025		December 31, 2024
Goodwill	**$**	**73,452**	$	73,452

Impairment test of goodwill

The Company performed its annual test for goodwill impairment at the balance sheet date in accordance with its policy described in note 3 - Summary of Material Accounting Policies. The Company has allocated goodwill to the Colombia operating segment.

The estimated fair value less costs of disposal of the Colombia operating segment exceeded the carrying value. As a result, no goodwill impairment was recorded.

Valuation Techniques

The recoverable amount of the group of CGUs to which the goodwill was assigned is based on fair value less costs of disposal. The technique used in determining the recoverable amount is based on the net present value of the after-tax cash flows from oil and gas reserves of the group of CGUs based on reserves estimated by Parex's independent reserve evaluator and the fair value of undeveloped land based on estimates with consideration given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant group of CGUs. The discounting process uses a rate of return that is commensurate with the risk associated with the assets and the time value of money. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs.

Significant Assumptions

Oil Reserves

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being revised.

Future Oil Prices

Oil forward price estimates are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors. The future oil prices used in the model are based on a forecast of crude oil prices by Parex's independent reserve evaluator.

Prices used at December 31, 2025 are as follows:

	2026	**2027**	**2028**	**2029**	**2030**	**Thereafter**
Brent ($US/bbl)	63.25	70.00	74.08	76.32	77.84	2% increase per year
WTI ($US/bbl)	59.25	66.00	70.00	72.16	73.60	2% increase per year

Prices used at December 31, 2024 are as follows:

	2025	**2026**	**2027**	**2028**	**2029**	**Thereafter**
Brent ($US/bbl)	75.25	77.50	80.08	82.69	84.34	2% increase per year
WTI ($US/bbl)	71.25	73.50	76.00	78.53	80.10	2% increase per year

Discount Rate

The Company assumed a discount rate in order to calculate the present value of its projected cash flows. The discount rate represented a weighted average cost of capital ("WACC") for comparable companies operating in similar industries, based on publicly available information. The WACC is an estimate of the overall required rate of return on an investment for both debt and equity owners and serves as the basis for developing an appropriate discount rate. Its determination requires separate analysis of the cost of equity and debt and considers a risk premium based on an assessment of risks related to the projected cash flows of the group of Colombia based CGUs whose revenues are denominated in USD. The after-tax discount rate used in performing the impairment test was 14% (year ended December 31, 2024 - 14%).

The fair value of the group of Colombian CGUs was in excess of its carrying value. Based on sensitivity analysis, no reasonably possible change in discount rate assumptions would cause the carrying amount of the group of Colombia CGUs to exceed its recoverable amount.

15. Oil and Natural Gas Sales and Other Revenue

The Company's oil and natural gas production sales is determined pursuant to the terms of the revenue agreements. The transaction price for crude oil and natural gas is based on the commodity price in the month of production, adjusted for quality, location, allowable deductions, if any, or other factors. Commodity prices are based on market indices that are determined on a monthly or daily basis.

The Company's oil and natural gas sales by product are as follows:

For the year ended December 31,		**2025**		2024
Crude oil	**$**	**975,687**	$	1,267,178
Natural gas		**30,155**		12,851
Oil and natural gas sales	**$**	**1,005,842**	$	1,280,029

At December 31, 2025, receivables from contracts with customers, which are included in accounts receivable, were $72.3 million (December 31, 2024 - $77.1 million).

The Company's other revenue includes pipeline transportation revenue and revenue related to energy generation and use of infrastructure:

For the year ended December 31,		**2025**		2024
Other Revenue	**$**	**9,826**	$	8,157

16. Other Expense

For the year ended December 31,		**2025**		2024
Other Colombian taxes	**$**	**8,850**	$	1,611
Colombian tax credit purchased		**8,097**		—
Legal provisions		**8,625**		—
Loss on settlement of decommissioning liabilities		**147**		1,593
Loss on disposition of tangible assets		**500**		1,987
Other		**2,981**		1,036
Total other expense	**$**	**29,200**	$	6,227

For the year ended December 31,		**2025**		2024
Non-cash other expense	**$**	**9,272**	$	3,580
Cash other expense		**19,928**		2,647
Total other expense	**$**	**29,200**	$	6,227

Legal provisions have been recognized in respect of estimated fines and penalties mainly arising from environmental regulatory disputes. Management has assessed the likelihood of settlement and determined the best estimate based on relevant legislation and the probability of enforcement outcomes. The timing of the outflows is expected within 10 years. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

17. Net Finance Expense

For the year ended December 31,		2025		2024
Bank charges and credit facility fees	**$**	**4,748**	$	3,673
Interest on bank debt		**2,765**		4,174
Accretion on decommissioning and environmental liabilities		**9,122**		9,206
Interest and other income		**(4,369)**		(4,315)
Bad debt expense		**3,442**		—
Expected credit loss (recovery) provision		**(53)**		67
Lease obligation interest expense		**365**		189
Other		**1,013**		1,099
Net finance expense	**$**	**17,033**	$	14,093

For the year ended December 31,		2025		2024
Non-cash finance expense		**12,511**	$	9,273
Cash finance expense		**4,522**		4,820
Net finance expense	**$**	**17,033**	$	14,093

18. Cash Settled Share-Based Compensation Liabilities

Cash settled share-based compensation liabilities are comprised of the following:

		December 31, 2025		December 31, 2024
Long-term CosRSUs and CosPSUs payable	**$**	**4,479**	$	4,000
Long-term LDRSUs and LDPSUs payable		**2,820**		619
Long-term DSUs payable		**4,524**		3,535
Long-term CRSUs payable		**3,405**		1,399
Total cash settled share-based compensation payable	**$**	**15,228**	$	9,553

19. Decommissioning and Environmental Liabilities

		Decommissioning		Environmental		Total
Balance, December 31, 2023	**$**	**71,523**	**$**	**24,209**	**$**	**95,732**
Additions		5,398		332		5,730
Settlements of obligations during the year		(7,038)		(3,235)		(10,273)
Loss on settlement of obligations		1,593		—		1,593
Accretion expense		6,853		2,353		9,206
Change in estimate - inflation and discount rates		(9,400)		(3,205)		(12,605)
Change in estimate - costs and timing of settlements		1,725		(8,342)		(6,617)
Foreign exchange gain		(2,185)		(2,906)		(5,091)
Balance, December 31, 2024	**$**	**68,469**	**$**	**9,206**	**$**	**77,675**
Additions		6,407		3,275		9,682
Property acquisitions - Note 11		702		118		820
Settlements of obligations during the year		(5,877)		(3,635)		(9,512)
Loss (gain) on settlement of obligations		596		(449)		147
Accretion expense		8,160		962		9,122
Change in estimate - inflation and discount rates		(6,197)		(1,192)		(7,389)
Change in estimate - costs and timing of settlements		2,216		1,490		3,706
Foreign exchange loss		3,087		1,827		4,914
Balance, December 31, 2025		**77,563**		**11,602**		**89,165**
Current obligation		(7,318)		(2,840)		(10,158)
Long-term obligation	**$**	**70,245**	**$**	**8,762**	**$**	**79,007**

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company's internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at December 31, 2025, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately $244.5 million as at December 31, 2025 (December 31, 2024 – $216.8 million) with the majority of these costs anticipated to occur in 2033 or later. A risk-free discount rate of 12.5% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2024 – 11.2% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used in 2025 and 2024 are based on forecast Colombia rates.

Included in the decommissioning liability is $7.3 million (December 31, 2024 – $11.7 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately $29.7 million as at December 31, 2025 (December 31, 2024 – $24.6 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.5% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2024 – 11.2% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used in 2025 and 2024 are based on forecast Colombia rates.

Included in the environmental liability is $2.8 million (December 31, 2024 – $2.9 million) that is classified as a current obligation.

Sensitivities
A change to the assumed discount rate or inflation rate would have the following impact on the decommissioning and environmental liabilities:

		2025		2024	
As at December 31,	**Sensitivity Range**	**Increase**	**Decrease**	Increase	Decrease
Risk-free discount rate	+/- one percent	**$ (5,551)**	**$ 6,157**	$ (5,349)	$ 6,022
Inflation rate	+/- one percent	**$ 6,600**	**$ (6,013)**	$ 6,406	$ (5,702)

20. Share Capital

a) Issued and outstanding common shares

	Number of shares		Amount
Balance, December 31, 2023	103,811,718	$	660,817
Issued for cash – exercise of options	22,168		309
Allocation of contributed surplus – exercise of options	—		102
Repurchase of shares	(5,494,850)		(28,329)
Balance, December 31, 2024	98,339,036	$	632,899
Repurchase of shares	(2,364,900)		(11,837)
Balance, December 31, 2025	**95,974,136**	**$**	**621,062**

The Company has authorized an unlimited number of voting common shares without nominal or par value.

In 2025, no options were exercised (year ended December 31, 2024 - 22,168 options were exercised for proceeds of $0.3 million).

In 2025, the Company repurchased 2,364,900 common shares pursuant to its Normal Course Issuer Bid ("NCIB") for $26.5 million at an average cost per share of Cdn$15.37 (year ended December 31, 2024 - 5,494,850 common shares repurchased for $73.8 million at an average cost per share of Cdn$18.04). The cost to repurchase common shares at a price in excess of their average book value has been charged to retained earnings.

Dividends paid in 2025 were $107.7 million or Cdn$1.54 per share (year ended December 31, 2024 - $112.2 million or Cdn$1.53 per share) to shareholders on record for each dividend payment.

b) Stock options

The Company has a stock option plan which provides for the issuance of options to the Company's officers and certain employees to acquire common shares. The maximum number of options reserved for issuance under the stock option plan may not exceed 5% of the number of common shares issued and outstanding. The stock options vest over a three-year period and expire five years from the date of grant.

	Number of options	Weighted average exercise price Cdn$/option
Balance, December 31, 2023	690,645	23.32
Granted	248,842	21.06
Exercised	(22,168)	18.75
Forfeited	(17,890)	24.67
Balance, December 31, 2024	899,429	22.78
Granted	533,022	12.74
Forfeited	(178,843)	21.52
Balance, December 31, 2025	**1,253,608**	**18.69**

Stock options outstanding and the weighted average remaining life of the stock options at December 31, 2025 are as follows:

	Options outstanding			Options vested		
Exercise price Cdn$	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn$/option	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn$/option
$12.74 - $16.90	518,558	4.18	12.74	—	—	—
$16.91 - $21.35	238,028	3.18	21.06	79,335	3.18	21.06
$21.36 - $22.71	153,009	0.11	21.69	153,009	0.11	21.69
$22.72 - $24.12	188,369	2.10	22.77	125,564	2.10	22.77
$24.13 - $27.02	155,644	1.09	27.00	155,644	1.09	27.00
	1,253,608	**2.80**	**18.69**	**513,552**	**1.37**	**23.47**

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

For the year ended December 31,	**2025**	2024
Risk-free interest rate (%)	**2.66**	3.67
Expected life (years)	**4**	4
Expected volatility (%)	**41**	47
Forfeiture rate (%)	**3**	3
Expected dividend yield (%)	**8.35**	10.56

The weighted average fair value at the grant date for the year ended December 31, 2025 was Cdn$1.68 per option (year ended December 31, 2024 – Cdn$5.10 per option). The weighted average share price on the exercise date for options exercised for the year ended December 31, 2024 was Cdn$22.14.

c) Equity settled share-based compensation

For the year ended December 31,		**2025**		2024
Option expense	**$**	**714**	$	878
Total equity settled share-based compensation expense	**$**	**714**	$	878

21. Cash Settled Incentive Plans

a) Cash or share settled Restricted Share Units and Performance Share Units ("CosRSUs and CosPSUs")

The Company has in place a Cash or share settled RSU/PSU incentive plan. This plan provides for the issuance of RSUs and PSUs to certain employees of Parex Canada. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise or the employee can elect to receive the award in Parex common shares. CosRSUs and CosPSUs vest over a three-year period and are exercised at the vest date.

CosRSUs:	Number of CosRSUs	Weighted average exercise price Cdn$/CosRSU
Balance, December 31, 2023	1,236,515	—
Granted[1]	683,101	—
Exercised	(593,565)	—
Forfeited	(163,799)	—
Balance, December 31, 2024	1,162,252	—
Granted[1]	1,037,144	—
Exercised	(569,595)	—
Forfeited	(133,366)	—
Balance, December 31, 2025	**1,496,435**	**—**

[1] Grants include units related to dividend equivalents granted on awards outstanding.

CosPSUs:	Number of CosPSUs	Weighted average exercise price Cdn$/CosPSU
Balance, December 31, 2023	821,865	—
Granted[1]	151,779	—
Granted by performance factor	57,567	—
Exercised	(345,774)	—
Forfeited	(2,850)	—
Balance, December 31, 2024	682,587	—
Granted[1]	156,917	—
Granted by performance factor	40,596	—
Exercised	(303,208)	—
Forfeited	(28,793)	—
Balance, December 31, 2025	**548,099**	**—**

[1] Grants include units related to dividend equivalents granted on awards outstanding.

As at December 31, 2025, no CosRSUs and CosPSUs were vested.

The weighted average fair value at the grant date for the year ended December 31, 2025 was Cdn$12.84 per CosRSU and CosPSU (year ended December 31, 2024 - Cdn$20.75 per CosRSU and CosPSU). The weighted average share price on the exercise date for CosRSUs and CosPSUs exercised in 2025 was Cdn$13.81 (year ended December 31, 2024 – Cdn$21.72).

Pursuant to the cash or share settled restricted share unit and performance share unit plan, the Company has granted performance share units to certain employees. The CosPSUs vest three years after the grant date. CosPSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a predetermined adjustment factor of between 0-2x is applied to CosPSUs eligible to vest at the end of the performance period. In March 2025 the board of directors approved a multiplier of 1.15X be applied to the 2022 CosPSU grant resulting in 40,596 CosPSUs issued. In March 2024 the board of directors approved a multiplier of 1.25X be applied to the 2021 CosPSU grant resulting in 57,567 CosPSUs issued.

Obligations for payments of cash under the CosRSUs and CosPSUs plans are accrued as compensation expense over the vesting period based on the fair value of CosRSUs and CosPSUs. The fair value of CosRSUs and CosPSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. As at December 31, 2025, the total CosRSUs and CosPSUs liability accrued is $18.8 million (December 31, 2024 - $11.2 million) of which $4.5 million (December 31, 2024 - $4.0 million) is classified as long-term in accordance with the three-year vesting period.

b) Long Duration Restricted Share Units and Performance Share Units ("LDRSUs and LDPSUs")

In May 2024, Parex put in place a long duration RSU/PSU incentive plan. This plan provides for the issuance of LDRSUs and LDPSUs to certain employees of Parex Canada. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise, or the employee can elect to receive the award in common shares. LDRSUs vest over a three-year period and expire 10 years from the date of grant. LDPSUs vest three years after the grant date and expire 10 years from the date of grant.

LDRSUs:	Number of LDRSUs	Weighted average exercise price Cdn$/LDRSU
Balance, December 31, 2023	—	—
Granted[1]	154,383	—
Forfeited	(51,888)	—
Balance, December 31, 2024	102,495	—
Granted[1]	208,953	—
Balance, December 31, 2025	**311,448**	**—**

[1] Grants include units related to dividend equivalents granted on awards outstanding.

LDPSUs:	Number of LDPSUs	Weighted average exercise price Cdn$/LDPSU
Balance, December 31, 2023	—	—
Granted[1]	208,577	—
Balance, December 31, 2024	208,577	—
Granted[1]	414,321	—
Balance, December 31, 2025	**622,898**	**—**

[1] Grants include units related to dividend equivalents granted on awards outstanding.

As at December 31, 2025, 38,421 LDRSUs and no LDPSUs were vested. As at December 31, 2024, no LDRSUs and LDPSUs were vested.

The weighted average fair value at the grant date for the year ended December 31, 2025 was Cdn$12.74 per LDRSU and LDPSU (year ended December 31, 2024 - Cdn$21.06 per LDRSU and LDPSU).

Pursuant to the long duration restricted share unit and performance share unit plan, the Company has granted performance share units to certain employees. The LDPSUs vest three years after the grant date and expire 10 years after the grant date. LDPSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to LDPSUs eligible to vest at the end of the performance period.

Obligations for payments of cash under the LDRSUs and LDPSUs plans are accrued as compensation expense over the vesting period based on the fair value of LDRSUs and LDPSUs. The fair value of LDRSUs and LDPSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. As at December 31, 2025, the total LDRSUs and LDPSUs liability accrued is $4.0 million (December 31, 2024 - $0.9 million) of which $2.8 million (December 31, 2024 - $0.6 million) is classified as long-term in accordance with the three-year vesting period.

c) *Deferred share units ("DSUs")*

The Company has in place a deferred share unit plan pursuant to which the Company may grant deferred shares to all non-employee directors. The deferred share units vest immediately and are settled in cash upon the retirement of the non-employee director from the Parex Board. The value of the DSUs at the exercise date is equivalent to the five-day weighted average share price at which the common shares of the Company traded for immediately preceding the exercise date. DSUs can only be redeemed following retirement from the Board of Directors of the Company in accordance with the terms of the DSU Plan. The DSUs liability cannot be settled by the issuance of common shares.

	Number of DSU's	Weighted average exercise price Cdn$/DSU
Balance, December 31, 2023	313,294	—
Granted[(1)]	57,382	—
Exercised on board retirement	(21,864)	—
Balance, December 31, 2024	348,812	—
Granted[(1)]	128,621	—
Exercised on board retirement	(68,767)	—
Balance, December 31, 2025	**408,666**	—

[(1)] Grants include units related to dividend equivalents granted on awards outstanding.

The fair value at the grant date is equivalent to the five-day weighted average share price at which the common shares of the Company traded for immediately preceding the grant date. The weighted average fair value at the grant date for the year ended December 31, 2025 was Cdn$12.07 per DSU (year ended December 31, 2024 - Cdn$23.87 per DSU). The weighted average share price on the exercise date for DSUs exercised in 2025 was Cdn$18.12 (year ended December 31, 2024 – Cdn$18.43).

Given the DSUs vest immediately, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately based on the fair value of the DSU. As at December 31, 2025, the total DSUs liability accrued is $5.5 million (December 31, 2024 - $3.5 million) of which $4.5 million (December 31, 2024 - $3.5 million) is classified as long-term in accordance with the terms of the DSU plan.

d) *Cash settled restricted share units ("CRSUs")*

Parex Colombia has a cash settled restricted share unit plan that provides for the issuance of CRSUs to certain employees of Parex Colombia. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise. CRSUs vest over a three-year period and are exercised at the vest date. The CRSUs liability cannot be settled by the issuance of common shares.

	Number of CRSUs	Weighted average exercise price Cdn$/CRSU
Balance, December 31, 2023	679,112	—
Granted[(1)]	569,740	—
Exercised	(350,201)	—
Forfeited	(87,975)	—
Balance, December 31, 2024	810,676	—
Granted[(1)]	1,008,076	—
Exercised	(371,742)	—
Forfeited	(88,248)	—
Balance, December 31, 2025	**1,358,762**	**—**

[(1)] Grants include units related to dividend equivalents granted on awards outstanding.

The weighted average fair value at the grant date for the year ended December 31, 2025 was Cdn$12.81 per CRSU (year ended December 31, 2024 - Cdn$20.96 per CRSU). The weighted average share price on the exercise date for CRSUs exercised in 2025 was Cdn$14.04 (year ended December 31, 2024 – Cdn$21.44).

Obligations for payments of cash under the CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares at the valuation date. As at December 31, 2025, the total CRSUs liability accrued is $9.3 million (December 31, 2024 - $4.4 million) of which $3.4 million (December 31, 2024 - $1.4 million) is classified as long-term in accordance with the three-year vesting period.

e) Cash settled share-based compensation

For the year ended December 31,		2025		2024
CosRSUs and CosPSUs expense	**$**	**16,299**	$	1,695
LDRSUs and LDPSUs expense		**3,196**		851
DSUs expense (recovery)		**2,859**		(2,085)
CRSUs expense		**7,448**		123
Total cash settled share-based compensation expense	**$**	**29,802**	$	584
Cash payments made upon exercise	**$**	**12,784**	$	20,647

22. Income Tax

The components of tax expense for 2025 and 2024 were as follows:

For the year ended December 31,		2025		2024
Current tax expense	**$**	**34,121**	$	89,492
Adjustments in respect of prior period		**(619)**		897
Total current tax expense	**$**	**33,502**	$	90,389
Deferred tax (recovery) expense		**(53,779)**		158,203
Total tax (recovery) expense	**$**	**(20,277)**	$	248,592

In December 2021, the Organization for Economic Co-operation and Development ("OECD") issued model rules for a new global minimum tax framework ("Pillar Two"). In May 2023, the IASB issued amendments to IAS 12 Income Taxes ("IAS 12") to address Pillar Two, which provide clarity on the impacts and additional disclosure requirements once the legislation is substantively enacted. The impact of Pillar Two has been considered and assessed. Based on the analysis performed, the Company is not expected to be subject to any additional tax liabilities under the Pillar Two legislation. As a result, no Pillar Two impacts have been recognized in the deferred tax calculations.

Factors affecting tax expense for the year

The standard Colombian corporate income tax rate for 2025 was 35%. An additional surtax between 5-15% may apply when certain conditions are met, as Parex is an oil producing entity under Colombian law. This surtax was not applicable in 2025 due to Brent crude prices relative to historical averages; accordingly, the Company's total Colombian corporate income tax rate for 2025 was 35% (year ended December 31, 2024 – 45%). The following is a reconciliation of income taxes calculated at the Colombian corporate tax rate to the tax expense for 2025 and 2024:

For the year ended December 31,		2025		2024
Income before tax	**$**	**234,806**	$	309,272
Income before tax multiplied by the standard rate of Colombian corporate tax of 35% (2024 – 45%)		**82,182**		139,172
Effects of:				
Income taxes recorded at rates different from the Colombian tax rate		**13,173**		1,321
Impact of Colombian tax rate changes		**8,572**		(2,661)
Non-deductible expense and other permanent differences		**(12,240)**		(9,669)
Share-based compensation		**164**		202
Adjustment in respect of prior period		**(1,515)**		(364)
Foreign exchange impact on tax pools denominated in foreign currency		**(120,553)**		119,158
Change in unrecognized deferred tax assets		**9,940**		1,433
Total tax (recovery) expense	**$**	**(20,277)**	$	248,592

Colombian current tax rates are as follows: 35% for 2025 and thereafter plus an applicable surtax for Colombian oil producing companies of between 0% to 15% dependent on the price of Brent crude relative to historical averages.

The analysis of deferred income tax assets as follows:

	December 31, 2025	December 31, 2024
Deferred tax assets to be settled within 12 months	**$ 1,965**	$ 1
Deferred tax assets to be settled after more than 12 months	**164,678**	103,535
Deferred income tax assets	**$ 166,643**	$ 103,536

The analysis of deferred income tax liabilities as follows:

	December 31, 2025	December 31, 2024
Deferred tax liabilities to be settled within 12 months	**$ 531**	$ —
Deferred tax liabilities to be settled after more than 12 months	**$ 23,859**	15,061
Deferred income tax liability	**$ 24,390**	$ 15,061
Net deferred tax (asset)	**$ (142,253)**	$ (88,475)

The deferred income tax liabilities and assets to be settled (recovered) within 12 months represents management's estimate of the timing of the reversal of temporary differences and does not correlate to the current income tax expense of the subsequent year.
The movement during the year in the deferred income tax liabilities and the net components is as follows:

Deferred Tax (Liability)	December 31, 2025	Charged (credited) to the statement of comprehensive income	December 31, 2024	Charged (credited) to the statement of comprehensive income
PP&E	**$ (20,720)**	**$ (5,659)**	$ (15,061)	$ (15,061)
Other	**(3,670)**	**(3,670)**	**—**	—
Balance, end of year	**$ (24,390)**	**$ (9,329)**	$ (15,061)	$ (15,061)

The movement during the year in the deferred income tax assets and the net components is as follows:

Deferred Tax Asset	December 31, 2025	Charged (credited) to the statement of comprehensive income	December 31, 2024	Charged (credited) to the statement of comprehensive income
PP&E	**$ 111,309**	**$ 47,573**	$ 63,736	$ (128,796)
Loss carry forwards	**5,588**	**5,588**	—	—
Decommissioning liability	**38,341**	**4,941**	33,400	(7,765)
Other	**11,405**	**5,006**	6,400	(6,581)
Balance, end of year	**$ 166,643**	**$ 63,108**	$ 103,536	$ (143,142)

The Company has losses as well as other cumulative tax deductions in excess of book value in Canada available to reduce future taxable income in future years. At December 31, 2025, the deferred tax asset amount recorded in Canada is $6.0 million (December 31, 2024 - $3.0 million). The Company did not recognize deferred income tax assets on capital losses and other items in Canada of $35.0 million (December 31, 2024 - $32.0 million) and Switzerland of $7.0 million (December 31, 2024 - nil). Non-capital losses in Canada expire in 20 years and capital losses carry-forward indefinitely. Non-capital losses in Switzerland expire in 7 years and in Colombia expire in 12 years. Amounts denominated in foreign currency have been translated at the December 31, 2025 exchange rate. At December 31, 2025, the Company had the following losses carry-forward:

	Year of expiry			
	2032	**2037**	**Indefinitely**	**Total**
Switzerland	$ 63,000	—	—	63,000
Colombia	—	12,994	—	12,994
Canada	—	—	183,216	$ 183,216
Total	**$ 63,000**	**$ 12,994**	**$ 183,216**	**$ 259,210**

Earnings retained by subsidiaries amounted to $964.4 million at December 31, 2025 (December 31, 2024 - $1,681.2 million). No provision has been made for withholding and other taxes that would become payable on the distribution of these earnings as it is not expected that they will be remitted in the foreseeable future.

23. Net income per Share

a) Basic net income per share

For the year ended December 31,		**2025**		2024
Net income				
Net income for the purpose of basic net income per share	**$**	**255,083**	$	60,680
Weighted average number of shares for the purposes of basic net income per share (000's)		**97,176**		101,414
Basic net income per share	**$**	**2.62**	$	0.60

b) Diluted net income per share

For the year ended December 31,		**2025**		2024
Net income				
Net income used to calculate diluted net income per share	**$**	**255,083**	$	60,680
Weighted average number of shares for the purposes of basic net income per share (000's)		**97,176**		101,414
Dilutive effect of share options and RSUs on potential common shares		**47**		—
Weighted average number of shares for the purposes of diluted net income per share		**97,223**		101,414
Diluted net income per share	**$**	**2.62**	$	0.60

For the year ended December 31, 2025, 827,396 stock options (December 31, 2024 - 897,633) were excluded from the diluted weighted average shares calculation as they were anti-dilutive.

24. Supplemental Disclosure of Cash Flow Information

a) Reconciliation of cash and cash equivalents and restricted cash and cash equivalents

The following table provides a reconciliation of cash and cash equivalents and restricted cash and cash equivalents to the amounts shown in the consolidated statement of cash flows:

For the year ended December 31,		**2025**		2024		2023
Cash and cash equivalents	**$**	**58,328**	$	98,022	$	140,352
Restricted cash and cash equivalents - current		**5,424**		581		—
Restricted cash and cash equivalents - long-term[1]		**191**		3,184		3,556
Total	**$**	**63,943**	$	101,787	$	143,908

(1) Included in Other long-term assets on the consolidated balance sheet.

b) Net change in assets and liabilities

For the year ended December 31,		**2025**		2024
Accounts receivable	**$**	**4,357**	$	35,881
Prepaids and other current assets		**15,685**		15,948
Marketable securities		**(45,090)**		—
Crude oil inventory		**(2,310)**		2,237
Current income tax receivable/payable		**(34,768)**		(4,583)
Accounts payable and accrued liabilities		**84,831**		(129,321)
Depletion related to crude oil inventory		**796**		(533)
Decommissioning and environmental liabilities		**(9,512)**		(10,273)
Net change in assets and liabilities	**$**	**13,989**	$	(90,644)
Operating	**$**	**(30,229)**	$	(52,318)
Investing		**45,150**		(39,775)
Financing		**(932)**		1,449
Net change in assets and liabilities	**$**	**13,989**	$	(90,644)

c) Interest and taxes paid

For the year ended December 31,		**2025**		2024
Cash interest paid	**$**	**2,753**	$	4,265
Cash income taxes paid	**$**	**1,178**	$	—

25. Employee Salaries and Benefit Expenses

For the year ended December 31,		**2025**		2024
Salaries, bonuses and other short-term benefits	**$**	**61,525**	$	54,218
Equity settled share-based compensation		**714**		878
Cash settled share-based compensation		**29,802**		584
Total	**$**	**92,041**	$	55,680

Employee salaries, bonuses and short-term benefits are included in general and administrative expense in the consolidated statements of comprehensive income. Stock options, CosRSUs, CosPSUs, LDRSUs, LDPSUs, CRSUs and DSUs expense are included in share-based compensation expense in the consolidated statements of comprehensive income.

26. Capital Management

The Company's strategy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain the confidence of investors and capital markets.

The Company has a senior secured credit facility with a syndicate of banks which at December 31, 2025 had a borrowing base in the amount of $240.0 million (December 31, 2024 - $240.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash or letter of credit needs as they arise. As at December 31, 2025, $33.0 million (December 31, 2024 - $60.0 million) was drawn on the credit facility.

At December 31, 2025, performance guarantees were in place with the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petróleos S.A. ("Ecopetrol") joint venture blocks related to the exploration work commitments on its Colombian concessions in the amount of $235.1 million (December 31, 2024 - $160.7 million). The guarantees have been provided in the form of letters of credit for varying terms that are mainly provided by select Latin American banks on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks (see note 29 - Commitments and Contingencies).

As at December 31, 2025, the Company's net working capital surplus was $28.0 million (December 31, 2024 - $59.4 million surplus).

The Company has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure, share buy-back and dividend programs to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders' equity, the credit facility and its working capital. As at December 31, 2025 shareholders' equity was $1,952.9 million (December 31, 2024 - $1,831.3 million).

27. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash, accounts receivable, marketable securities, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity. The fair value of the revolving credit facility is equal to its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates.

Long-term financial instruments of the Company carried on the consolidated balance sheet are carried at amortized cost. Financial derivative instruments, specifically fixed price contracts, are carried at fair value.

The fair value of the Company's financial derivative instruments are quoted in active markets. The Company classifies the fair value of these transactions according to the following hierarchy:

Level 1 – quoted prices in active markets for identical financial instruments.

Level 2 – quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.
Level 3 – valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Company's marketable securities have been classified as level 1 based on the fair value hierarchy described above. Their fair value is determined using quoted market prices at each reporting date.

The Company's financial derivative instruments have been classified as level 2 based on the fair value hierarchy described above. The Company uses the following techniques to determine the fair value measurements: Crude oil and foreign currency contracts are recorded at their estimated fair value based on the difference between the contracted price and the period end forward price for the same commodity and foreign currency, using quoted market prices or the period end forward price for the same commodity and foreign currency, extrapolated to the end of the contract term.

As at December 31, 2025, with other variables unchanged, the impact on the Company's financial instruments of a 10% strengthening (weakening) of the Canadian dollar and COP against the US dollar would have decreased (increased) net income by approximately $8.7 million.

a) Credit risk

Credit risk is the risk of loss associated with the inability of a third party to fulfill its payment obligations. The Company is exposed to the risk that third parties that owe it money do not meet their obligations. The Company assesses the financial strength of its joint venture partners and oil marketing counterparties in its management of credit exposure.

The Company for the year ended December 31, 2025 had the majority of its oil sales to one counterparty. Accounts receivable balance as at December 31, 2025 are substantially made up of receivables with customers in the oil and gas industry and are subject to normal industry credit risks. The Company historically has not experienced any collection issues with its crude oil customers.

As at December 31, 2025 and 2024 the Company's accounts receivable are aged as follows:

For the year ended December 31,	**2025**	2024
Current (less than 90 days)	**$ 78,329**	$ 82,686
Past due (more than 90 days)	**—**	—
Total	**$ 78,329**	$ 82,686

For the year ended December 31, 2025 the Company recorded a provision for unrecoverable advances to a supplier for materials in the amount of $3.4 million.

None of the Company's receivables are impaired at December 31, 2025. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

b) Liquidity risk

The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Management typically forecasts cash flows for a period of 12 to 36 months to identify any financing requirements. Liquidity is managed through daily and longer-term cash, debt and equity management strategies. These include estimating future cash generated from operations based on reasonable production and pricing assumptions, estimating future discretionary and non-discretionary capital expenditures and assessing the amount of equity or debt financing available. The Company is committed to maintaining a strong balance sheet and has the ability to change its capital program based on expected operating cash flows. The balance drawn on the Company's $240.0 million credit facility at December 31, 2025 was $33.0 million (December 31, 2024 - $240.0 million facility, $60.0 million drawn).

The following are the contractual maturities of financial liabilities at December 31, 2025:

	Less than 1 year	**1-3 Years**	**4-5 Years**	**Thereafter**	**Total**
Accounts payable and accrued liabilities	212,081	—	—	7,143	$ 219,224
Bank debt including interest	—	36,181	—	—	36,181
Lease obligation	1,331	7,814	—	—	9,145
Cash settled share-based compensation payable	22,397	15,228	—	—	37,625
Total	**$ 235,809**	**59,223**	**—**	**7,143**	**$ 302,175**

The following are the contractual maturities of financial liabilities at December 31, 2024:

	Less than 1 year	1-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	$ 159,773	—	—	—	$ 159,773
Derivative financial instruments	1,160	—	—	—	1,160
Bank debt including interest	—	66,287	—	—	66,287
Lease obligation	581	4,622	—	—	5,203
Cash settled share-based compensation payable	10,377	9,553	—	—	19,930
Total	$ 171,891	80,462	—	—	$ 252,353

c) Commodity price risk

The Company is exposed to commodity price movements as part of its operations, particularly in relation to the prices received for its oil production. Crude oil is sensitive to numerous worldwide factors, many of which are beyond the Company's control. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Consequently, these changes could also affect the value of the Company's properties, the level of spending for exploration and development and the ability to meet obligations as they come due. The Company's oil production is sold under short-term contracts, exposing it to the risk of near-term price movements.

As at December 31, 2025, the Company had no commodity price risk management contracts in place.

The following is a summary of the commodity price risk management contracts entered into subsequent to December 31, 2025:

Period Hedged	Reference	Volume bbls/d	Call strike price	Put Strike	Low Put Strike	Premium
January 1, 2026 to January 31, 2026	ICE Brent	12,000	$70.00	$60.00	$55.00	$0.65
April 1, 2026 to April 30, 2026	ICE Brent	12,000	$70.00	$60.00	$53.00	$—
May 1, 2026 to May 31, 2026	ICE Brent	12,000	$70.00	$60.00	$53.00	$—
June 1, 2026 to June 30, 2026	ICE Brent	12,000	$70.00	$60.00	$53.00	$—

The table below summarizes the loss on the commodity price risk management contracts that were in place during the years ended December 31, 2025 and 2024:

For the year ended December 31,	**2025**	2024
Premiums paid on commodity price risk management contracts	**$ 7,935**	$ —
Unrealized (gain) loss on commodity price risk management contracts	**(1,160)**	1,160
Realized gain on commodity price risk management contracts	**(5,356)**	—
Total	**$ 1,419**	$ 1,160

d) Foreign currency risk

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Canadian dollars (Cdn$) and Colombian pesos (COP$) while its committed capital expenditures are expected to be primarily denominated in US dollars.

As at December 31, 2025, the Company had no foreign currency risk management contracts in place.

The following is a summary of the foreign currency risk management contracts entered into subsequent to December 31, 2025:

Period Hedged	**Reference**	**Currency Option Type**	**Amount USD**	**Strike Price COP**	**Max compensation**
January 16, 2026 to December 15, 2026	COP	Collar with limited compensation	$99,000,000	3,700-4,200	800

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the years ended December 31, 2025 and 2024:

For the year ended December 31,		**2025**		2024
Realized gain on foreign currency risk management contracts	**$**	**(8,998)**	$	—
Total	**$**	**(8,998)**	$	—

e) Market risk

Parex is exposed to market risk associated with its marketable securities, including the GeoPark Shares, primarily driven by changes in the market price and liquidity of the securities. The market price of the GeoPark Shares may be volatile and could be adversely affected by general market conditions, the investee's performance and disclosures, oil and gas commodity prices, interest and foreign exchange rates, geopolitical developments in the investee's areas of operation, and other factors beyond the Company’s control.

28. Segmented Information

The Company has foreign subsidiaries, and the following segmented information is provided:

For the year ended December 31, 2025	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 1,005,842	$ 1,005,842
Royalties	—	(126,752)	(126,752)
Net revenue	—	879,090	879,090
Other revenue	—	9,826	9,826
Commodity risk management contracts (loss)	—	(1,419)	(1,419)
Revenue	—	887,497	887,497
Expenses			
Production	—	225,543	225,543
Transportation	—	76,444	76,444
Purchased oil	—	162	162
General and administrative	34,400	36,926	71,326
Impairment of exploration and evaluation assets	—	11,140	11,140
Impairment of property, plant and equipment assets	—	—	—
Impairment of long-term inventory	—	6,470	6,470
Equity settled share-based compensation expense	714	—	714
Cash settled share-based compensation expense	22,354	7,448	29,802
Depletion, depreciation and amortization	3,053	197,352	200,405
Other expense	—	29,200	29,200
Foreign exchange gain	(466)	(10,466)	(10,932)
Unrealized gain on marketable securities	(4,616)	—	(4,616)
	55,439	580,219	635,658
Finance (income)	(467)	(3,902)	(4,369)
Finance expense	6,084	15,318	21,402
Net finance expense	5,617	11,416	17,033
Income (loss) before taxes	(61,056)	295,862	234,806
Current tax expense (recovery)	(427)	33,929	33,502
Deferred tax (recovery)	(3,177)	(50,602)	(53,779)
Net income (loss)	**$ (57,452)**	**$ 312,535**	**$ 255,083**
Capital assets (end of year)	$ 7,207	$ 1,654,131	$ 1,661,338
Capital expenditures	$ 1,340	$ 308,985	$ 310,325
Total assets (end of year)	$ 69,132	$ 2,271,960	$ 2,341,092

For the year ended December 31, 2024	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 1,280,029	$ 1,280,029
Royalties	—	(201,418)	(201,418)
Net revenue	—	1,078,611	1,078,611
Other revenue	—	8,157	8,157
Commodity risk management contracts (loss)	—	(1,160)	(1,160)
Revenue	—	1,085,608	1,085,608
Expenses			
Production	—	255,278	255,278
Transportation	—	65,745	65,745
Purchased oil	—	904	904
General and administrative	37,435	31,473	68,908
Impairment of exploration and evaluation assets	—	54,085	54,085
Impairment of property, plant and equipment assets	—	78,417	78,417
Impairment of long-term inventory	—	10,000	10,000
Equity settled share-based compensation expense	878	—	878
Cash settled share-based compensation expense	461	123	584
Depletion, depreciation and amortization	2,735	213,035	215,770
Other expense	—	6,227	6,227
Foreign exchange loss	705	4,742	5,447
	42,214	720,029	762,243
Finance (income)	(832)	(3,483)	(4,315)
Finance expense	6,173	12,235	18,408
Net finance expense	5,341	8,752	14,093
Income (loss) before taxes	(47,555)	356,827	309,272
Current tax expense (recovery)	(3,124)	93,513	90,389
Deferred tax expense	3,796	154,407	158,203
Net income (loss)	**$ (48,227)**	**$ 108,907**	**$ 60,680**
Capital assets (end of year)	$ 8,919	$ 1,527,310	$ 1,536,229
Capital expenditures	$ 3,820	$ 343,875	$ 347,695
Total assets (end of year)	$ 54,088	$ 2,100,974	$ 2,155,062

For the year ended December 31, 2025, the Company had one external customer (year ended December 31, 2024 - two external customers), in the oil and gas industry that subject to normal industry credit risks, constituted more than 10% of commodity sales from production. Sales to these customers totaled $695.3 million for the year ended December 31, 2025, and $1,082.5 million for the year ended December 31, 2024, respectively.

29. Commitments and Contingencies

a) Colombia

At December 31, 2025, performance guarantees were in place with the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petróleos S.A. ("Ecopetrol") joint venture blocks in the amount of $235.1 million (December 31, 2024 - $160.7 million) to support the exploration work commitments on its Colombian concessions. The guarantees have been provided in the form of letters of credit for varying terms that are mainly provided by select Latin American banks on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks.

The value of the Company's exploration commitments as at December 31, 2025 in respect of the Colombia work commitments under E&P contracts, joint venture farm-in arrangements and business collaboration agreements are estimated to be as follows:

(000s)		
2026	$	59,737
2027		130,645
2028		100,515
2029		5,845
2030		—
Thereafter		456,746
Total	**$**	**753,488**

b) Operating leases

In the normal course of business, Parex has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. These commitments include leases for office space and accommodations.

The existing minimum lease payments for office space and accommodations at December 31, 2025 are as follows:

(000s)		Total	2026	2027	2028	2029	2030	Thereafter
Office and accommodations	$	6,966	2,987	2,034	778	778	389	—

30. Related Party Disclosures

a) Significant Subsidiaries

The consolidated financial statements include the financial statements of Parex Resources Inc. at December 31, 2025 and 2024. Transactions between subsidiaries are eliminated upon consolidation.

b) Compensation of Key Management Personnel

Key management personnel compensation, including directors, is as follows:

For the year ended December 31,		**2025**		2024
Salaries, directors' fees and other benefits	**$**	**4,306**	$	4,356
Equity settled share-based compensation		**439**		478
Cash settled share-based compensation		**4,568**		5,846
Total	**$**	**9,313**	$	10,680

c) Other transactions

The Company did not have any related party transactions with entities outside the consolidated group for the years ended December 31, 2025 and 2024.

31. Subsequent Events

NCIB

On January 22, 2026, the Company commenced an NCIB to purchase for cancellation, from time to time, as it considers advisable up to a maximum of 9,407,490 Common Shares on the open market through the facilities of the TSX and/or alternative trading systems. The NCIB will terminate on January 21, 2027.

Proposal

On February 23, 2026, the Company announced that it has submitted an acquisition proposal (the "Proposal") to the Board of Directors of Frontera Energy Corporation (TSX: FEC) ("Frontera") to acquire all of Frontera's Colombian upstream business in an all-cash offer for consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million.

Binding Proposal

On March 2, 2026, the Company submitted a binding acquisition proposal (the "Binding Proposal") to the Board of Frontera Energy Corporation (TSX: FEC) ("Frontera") to acquire all of Frontera's Colombian upstream business in an all-cash offer for consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million. On the same day, Frontera provided an update on the previously-announced non-binding proposal by Parex, acknowledging receipt of a binding offer of $525 million and awaiting confirmation of certain terms.

MD&A

FOR THE YEAR ENDED DECEMBER 31, 2025

PAREXRESOURCES.COM TSX | PXT

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Parex Resources Inc. ("Parex" or the "Company") for the three months and years ended December 31, 2025 and 2024 is dated March 3, 2026 and should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2025 and 2024 (the "audited consolidated financial statements"). The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"), representing generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada.

Additional information related to Parex is included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated March 3, 2026 (the "AIF"), and may be accessed through the SEDAR+ website at www.sedarplus.ca.

All financial amounts are in United States (US) dollars unless otherwise stated.

Company Profile

Parex is one of the largest independent oil and gas companies in Colombia, focusing on sustainable conventional production. The Company's corporate headquarters are in Calgary, Canada, with an operating office in Bogotá, Colombia. Parex shares trade on the Toronto Stock Exchange under the symbol PXT.

Abbreviations

Refer to the final page of the MD&A for commonly used abbreviations in the document. Refer to the Advisory on Forward-Looking Statements and Non-GAAP and Other Financial Measures Advisory.

References to crude oil or natural gas production in this MD&A refer to the light and medium crude oil and heavy crude oil and conventional natural gas, respectively, product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities ("NI 51-101").*

2025 Highlights

- Crude oil and natural gas production for the year averaged 44,701 boe/d, achieving annual guidance range of 43,000 to 47,000 boe/d, compared to 2024 average production of 49,924 boe/d. Refer to "Consolidated Results of Operations" for production split by product type.
- Realized net income of $255.1 million ($2.62 per share basic), compared to net income of $60.7 million ($0.60 per share basic) in 2024. The increase from the prior year is largely related to a decrease in tax expense and impairment expense, partially offset by a decrease in oil revenues from lower oil volumes sold and a decrease in realized sales price.
- Generated annual funds flow provided by operations ("FFO")(1) of $455.0 million ($4.68 per share basic(2)), compared to $622.2 million ($6.14 per share basic(2)) in 2024.
- Produced an operating netback of $35.52boe(2) (2024 - $41.30/boe(2)) and an FFO netback of $28.00/boe(2) (2024 - $33.95/boe(2)) from an average Brent crude oil price of $68.19/bbl (2024 - $79.86/bbl).
- Incurred capital expenditures(3) of $310.3 million (2024 - $347.7 million).
- Generated $144.7 million of free funds flow(3) that was used for return of capital initiatives and $27.0 million of bank debt repayment; at December 31, 2025, bank debt was $33.0 million; working capital surplus(1) was $28.0 million and cash was $58.3 million.
- Paid a C$1.54 per share(4) regular dividend and repurchased 2,364,900 shares pursuant to the Company's normal course issuer bid ("NCIB"). A total of $134.2 million was returned to shareholders through dividends of $107.7 million and share repurchases of $26.5 million.

Three Months Ended December 31, 2025 ("fourth quarter" or "Q4") Highlights

- Crude oil and natural gas production in Q4 2025 averaged 48,606 boe/d. Average production in 2025 increased 7% compared to 2024 average production of 45,297 boe/d. Refer to "Consolidated Results of Operations" for production split by product type.
- Recognized net income of $74.9 million ($0.78 per share basic) compared to a net loss of $69.1 million ($0.70 per share basic) in 2024. The increase from the prior year is largely related to a decrease in tax expense and impairment expense.
- Generated quarterly FFO(1) of $122.9 million ($1.28 per share basic(2)), compared to $141.2 million ($1.43 per share basic(2)) in the fourth quarter of 2024.
- Produced an operating netback(2) of $32.10/boe (Q4 2024 - $34.90/boe) and an FFO netback(2) of $28.19/boe (Q4 2024 - $32.39/boe) from an average Brent crude oil price of $63.08/bbl (2024 - $74.01/bbl).
- Generated $38.3 million of free funds flow(3) that was used for return of capital initiatives.
- Paid a C$0.385 per share(4) regular quarterly dividend and repurchased 580,000 shares pursuant to the Company's NCIB.

(1) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".
(2) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".
(3) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(4) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Financial Summary

	For the three months ended December 31,		For the year ended December 31,		
(Financial figures in $000s except per share amounts)	**2025**	2024	**2025**	2024	2023
Light Crude Oil and Medium Crude Oil (bbl/d)	**14,835**	9,550	**11,635**	8,850	8,417
Heavy Crude Oil (bbl/d)	**32,267**	34,882	**31,887**	40,336	45,163
Average oil production (bbl/d)(1)	**47,102**	44,432	**43,522**	49,186	53,580
Average conventional natural gas production (mcf/d)(1)	**9,024**	5,190	**7,071**	4,428	4,656
Average oil and natural gas production (boe/d)	**48,606**	45,297	**44,701**	49,924	54,356
Production split (% crude oil)	**97**	98	**97**	99	99
Oil and natural gas sales price ($/boe)(6)	**57.05**	63.73	**61.90**	69.80	70.71
Operating netback ($/boe)(1)	**32.10**	34.90	**35.52**	41.30	44.55
Oil and natural gas sales	**248,713**	277,824	**1,005,842**	1,280,029	1,408,703
Funds flow provided by operations(7)	**122,922**	141,201	**454,985**	622,233	667,782
Per share – basic(1)(3)	**1.28**	1.43	**4.68**	6.14	6.29
Per share – diluted(1)(3)	**1.28**	1.43	**4.68**	6.14	6.28
Net income (loss)	**74,865**	(69,051)	**255,083**	60,680	459,309
Per share – basic(3)	**0.78**	(0.70)	**2.62**	0.60	4.32
Per share – diluted(3)	**0.78**	(0.70)	**2.62**	0.60	4.32
Dividends paid	**26,853**	26,658	**107,671**	112,184	118,676
Per share – Cdn$(3)(6)	**0.385**	0.385	**1.54**	1.53	1.50
Shares repurchased	**7,644**	16,408	**26,514**	73,789	105,068
Number of shares repurchased (000s)	**580**	1,692	**2,365**	5,495	5,628
Capital expenditures(2)	**84,620**	82,110	**310,325**	347,695	483,343
Long-term inventory expenditures, net of transfers and sales	**(7,678)**	(2,569)	**(17,578)**	4,773	39,430
Free funds flow (2)	**38,302**	59,091	**144,660**	274,538	184,439
EBITDA(2)	**104,764**	(10,419)	**481,444**	545,362	650,829
Adjusted EBITDA(2)	**128,653**	137,312	**512,937**	720,089	817,280
Total assets (end of period)	**2,341,092**	2,155,062	**2,341,092**	2,155,062	2,415,327
Working capital surplus (end of period)(4)(7)	**28,027**	59,397	**28,027**	59,397	79,027
Bank debt (end of period)(5)	**33,000**	60,000	**33,000**	60,000	90,000
Weighted average shares outstanding (000s)					
Basic	**96,239**	99,063	**97,176**	101,414	106,247
Diluted	**96,374**	99,063	**97,223**	101,414	106,295
Outstanding shares (end of period) (000s)	**95,974**	98,339	**95,974**	98,339	103,812

(1) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(3) Per share amounts (with the exception of dividends) are based on weighted average common shares. Dividends paid per share are based on the number of common shares outstanding at each dividend record date.
(4) Working capital calculation does not take into consideration the undrawn amount available under the syndicated bank credit facility.
(5) Syndicated bank credit facility borrowing base of $240.0 million as at December 31, 2025 (December 31, 2024 - $240.0 million).
(6) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(7) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".

2025 Guidance vs Actuals

The table below is a summary of Parex's annual guidance for 2025 and a review of actual results:

Category	2025 Guidance (January 14, 2025)	2025 Actuals	% variance from 2025 Guidance - midpoint
Brent Crude Oil Average Price ($/bbl)	70	**68**	(3)
Average Production (boe/d)(1)	43,000-47,000	**44,701**	(1)
Funds Flow Provided by Operations Netback ($/boe)(3)	26-28	**28**	4
Funds Flow Provided by Operations ($ millions)(4)	425-465	**455**	2
Capital Expenditures ($ millions)(2)	285-315	**310**	3
Free funds Flow (mid-points) ($ millions)(2)	145	**145**	—
Current tax effective rate on FFO midpoint (%)(5)	3-6%	**7%**	40

(1) Refer to "Consolidated Results of Operations" for annual production split by product type.
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".
(4) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".
(5) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

In 2025, Brent crude prices were slightly below Parex's guidance. Average production volumes were within the guidance range, slightly below the midpoint, and capital expenditures were also within the budgeted range, consistent with midpoint production levels. Funds flow provided by operations and FFO netback were near the upper end of the 2025 guidance range, primarily due to favourable Vasconia differentials and lower than expected operated production expense. Lower operated production expense was driven by increased production from development activities, the LLA-32 tuck-in acquisition and new production from LLA-74, which improved fixed cost absorption, in addition to corporate efficiency initiatives implemented to reduce fixed and variable production costs.

Return of Capital to Shareholders

Parex looks to provide competitive return of capital to shareholders through dividends and share repurchases, while investing in the Company's assets to provide a total shareholder return. In 2025 Parex bought back 2% of its outstanding shares under the Company's NCIB and paid an annual dividend of C$1.54, which delivered a total return of capital of $134.2 million to shareholders during the year.

2026 Guidance

The following table summarizes the Company's 2026 annual guidance:

Category	2026 Guidance (January 19, 2026)
Brent Crude Oil Average Price ($/bbl)	60
Average Production (boe/d)(1)	45,000-49,000
Funds Flow provided by operations netback ($/boe)(1)(3)	23-24
Funds flow provided by operations ($ millions)(4)	385-420
Capital Expenditures ($ millions)(1)(2)	280-320
Free funds flow (mid-point) ($ millions)(1)(2)	105
Current tax effective rate on FFO midpoint (%)(1)(5)	1-3%

(1) See the Company's January 19, 2026 news release for additional details on 2026 corporate guidance and netback sensitivity estimates.
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".
(4) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".
(5) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

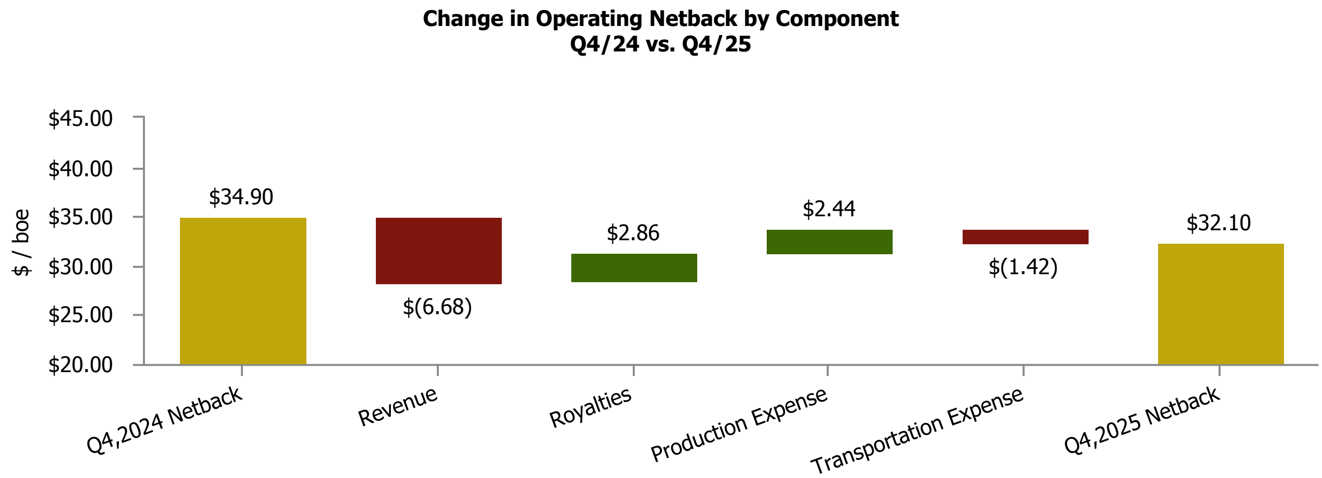
Financial and Operational Results

Consolidated Results of Operations

Parex's oil and gas operations are conducted in Colombia with head office functions conducted in Canada.

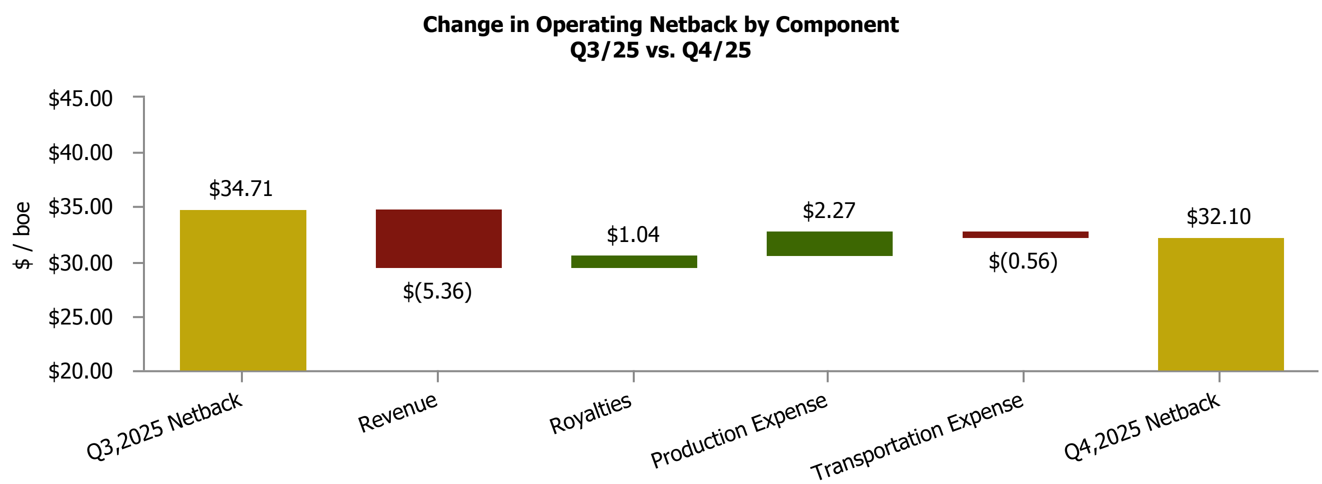
	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Average daily production				
Light Crude and Medium Crude Oil (bbl/d)	**14,835**	9,550	**11,635**	8,850
Heavy Crude Oil (bbl/d)	**32,267**	34,882	**31,887**	40,336
Crude oil (bbl/d)	**47,102**	44,432	**43,522**	49,186
Conventional Natural Gas (mcf/d)	**9,024**	5,190	**7,071**	4,428
Total (boe/d)	**48,606**	45,297	**44,701**	49,924
Production split (% crude oil production)	**97**	98	**97**	99
Average daily sales of oil and natural gas				
Produced crude oil (bbl/d)	**45,885**	46,520	**43,335**	49,342
Purchased crude oil (bbl/d)	**—**	—	**3**	28
Produced natural gas (mcf/d)	**9,024**	5,190	**7,071**	4,428
Total (boe/d)	**47,389**	47,385	**44,517**	50,108
Operating netback (000s)				
Oil and natural gas sales	**$ 248,713**	$ 277,824	**$ 1,005,842**	$ 1,280,029
Royalties	**(28,649)**	(41,094)	**(126,752)**	(201,418)
Net revenue[4]	**220,064**	236,730	**879,090**	1,078,611
Production expense	**(57,073)**	(67,708)	**(225,543)**	(255,278)
Transportation expense	**(23,081)**	(16,877)	**(76,444)**	(65,745)
Purchased oil expense	**—**	(59)	**(162)**	(904)
Operating netback[1]	**$ 139,910**	$ 152,086	**$ 576,941**	$ 756,684
Operating netback (per boe)				
Brent ($/bbl)	**$ 63.08**	$ 74.01	**$ 68.19**	$ 79.86
Parex price differential	**(6.03)**	(10.28)	**(6.29)**	(10.06)
Oil and natural gas sales[2]	**$ 57.05**	$ 63.73	**$ 61.90**	$ 69.80
Royalties[2]	**(6.57)**	(9.43)	**(7.80)**	(10.99)
Net revenue[2]	**50.48**	54.30	**54.10**	58.81
Production expense[2]	**(13.09)**	(15.53)	**(13.88)**	(13.93)
Transportation expense[2]	**(5.29)**	(3.87)	**(4.70)**	(3.58)
Operating netback[3]	**$ 32.10**	$ 34.90	**$ 35.52**	$ 41.30

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".
(4) Net revenue for the year ended December 31, 2023 was $1,164.0 million.



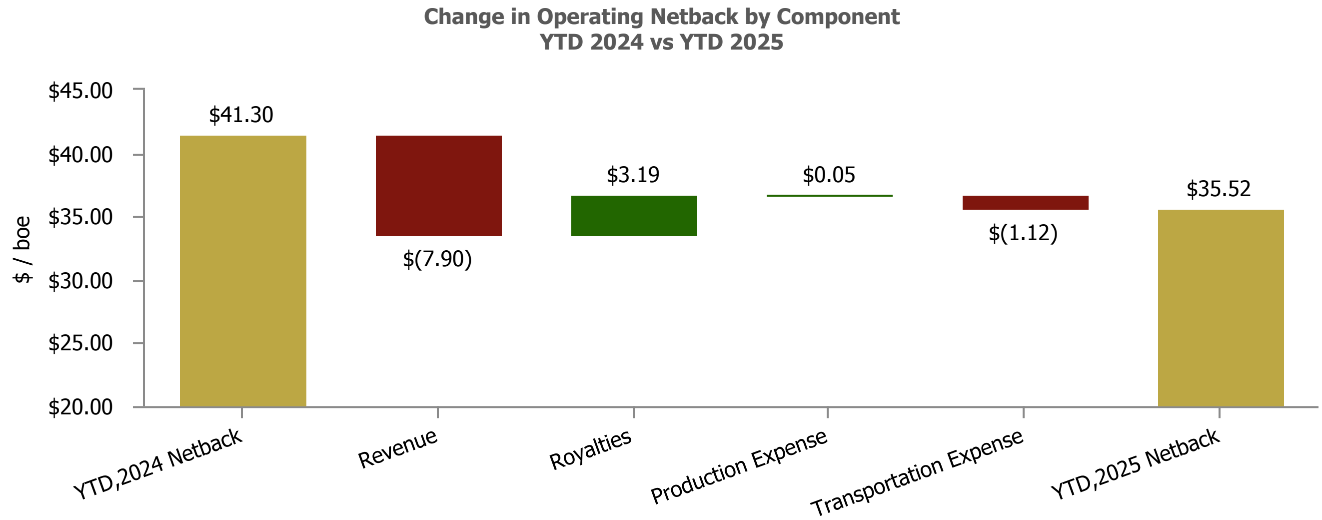
In the fourth quarter of 2025, the Company's benchmark Brent oil price decreased by $10.93/bbl, while revenue decreased by $6.68/boe as compared to the fourth quarter of 2024. The increase in revenue relative to the Brent crude oil benchmark decrease was attributed to improved location and quality differentials. Royalties decreased by $2.86/boe compared to the fourth quarter of 2024 as a result of lower production in areas where high price share royalties are applicable and a decrease in world oil prices. Production expense decreased by $2.44/boe compared to the fourth quarter of 2024 due to lower electrical power costs, reduced well workover and facility maintenance costs, and improved fixed cost absorption, partially offset by the appreciation of the Colombian peso. Transportation expense in the quarter increased by $1.42/boe compared to the fourth quarter of 2024 due to an increase in oil volumes transported by truck, higher gas volumes transported, and the appreciation of the Colombian peso.

Overall, the operating netback decreased by $2.80/boe compared to a Brent benchmark crude price decrease of $10.93/bbl.



In the fourth quarter of 2025, the Company's benchmark Brent oil price decreased by $5.09/bbl, while revenue decreased by $5.36/boe compared to the third quarter of 2025. The decrease in revenue relative to the Brent crude oil benchmark decrease was mainly a result of increased location and quality differentials. Royalties decreased by $1.04/boe as a result of lower production in areas where high price share royalties are applicable and a decrease in world oil prices. Production expense decreased by $2.27/boe due to lower electrical power costs, reduced well workover and facility maintenance costs, and improved fixed cost absorption, partially offset by the appreciation of the Colombian peso. Transportation expense in the quarter increased by $0.56/boe compared to the third quarter of 2025 due to an increase in oil volumes transported by truck, higher gas volumes transported, and the appreciation of the Colombian peso.

Overall, the operating netback decreased by $2.61/boe compared to a Brent benchmark crude price decrease of $5.09/bbl.



In 2025, the Company's benchmark Brent price decreased by $11.67/bbl, while revenue decreased by $7.90/boe compared to 2024. The increase in revenue relative to the Brent crude benchmark decrease was mainly the result of improved location and quality differentials. Royalties decreased by $3.19/boe as a result of lower production in areas where high price share royalties are applicable and a decrease in world oil prices. Production expense in 2025 decreased by $0.05/boe due to lower well workover and facility maintenance costs and improved fixed cost absorption, partially offset by higher electrical power costs, increased non-operated production expenses, and the appreciation of the Colombian peso. Transportation expense in 2025 increased by $1.12/boe compared to 2024 due to an increased in oil volumes transported by truck, higher gas volumes transported, and the appreciation of the Colombian peso.

Overall, the operating netback decreased by $5.78/boe compared to a Brent benchmark crude price decrease of $11.67/bbl.

Oil and Natural Gas Sales

a) Average Daily Production and Sales Volumes (boe/d)

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Block LLA-34	**19,719**	23,633	**21,033**	26,466
Southern Llanos Basin	**22,470**	15,227	**16,767**	16,550
Northern Llanos Basin	**2,848**	3,260	**3,556**	4,022
Magdalena Basin	**2,065**	2,312	**2,166**	2,148
Total Crude Oil Production	**47,102**	44,432	**43,522**	49,186
Natural gas production	**1,504**	865	**1,179**	738
Total crude oil and natural gas production	**48,606**	45,297	**44,701**	49,924
Crude oil inventory draw (build)	**(1,217)**	2,088	**(187)**	156
Average daily sales of produced oil and natural gas	**47,389**	47,385	**44,514**	50,080
Purchased oil	**—**	—	**3**	28
Sales Volumes	**47,389**	47,385	**44,517**	50,108
Average daily sales of produced oil and natural gas - operated	**28,038**	23,014	**23,817**	23,699
Average daily sales of produced oil and natural gas - non-operated	**19,351**	24,371	**20,697**	26,381
Average daily sales of produced oil and natural gas	**47,389**	47,385	**44,514**	50,080

Crude oil and natural gas production for the fourth quarter of 2025 averaged 48,606 boe/d. Q1 2026 production, through February 28, 2026, has averaged approximately 46,150 boe/d(1).

(1) Estimated average production for January 1, 2026 to February 28, 2026; light & medium crude oil: ~14,805 bbl/d, heavy crude oil: ~30,637 bbl/d, conventional natural gas: ~8.568 mcf/d; rounded for presentation purposes.

Fourth quarter of 2025 crude oil and natural gas production averaged 48,606 boe/d, an increase of approximately 7% from the fourth quarter of 2024 production of 45,297 boe/d and an increase of approximately 11% from the third quarter of 2025 production of 43,953 boe/d. Refer to "Summary of Quarterly Results" for production split by product type for third quarter 2025 production.

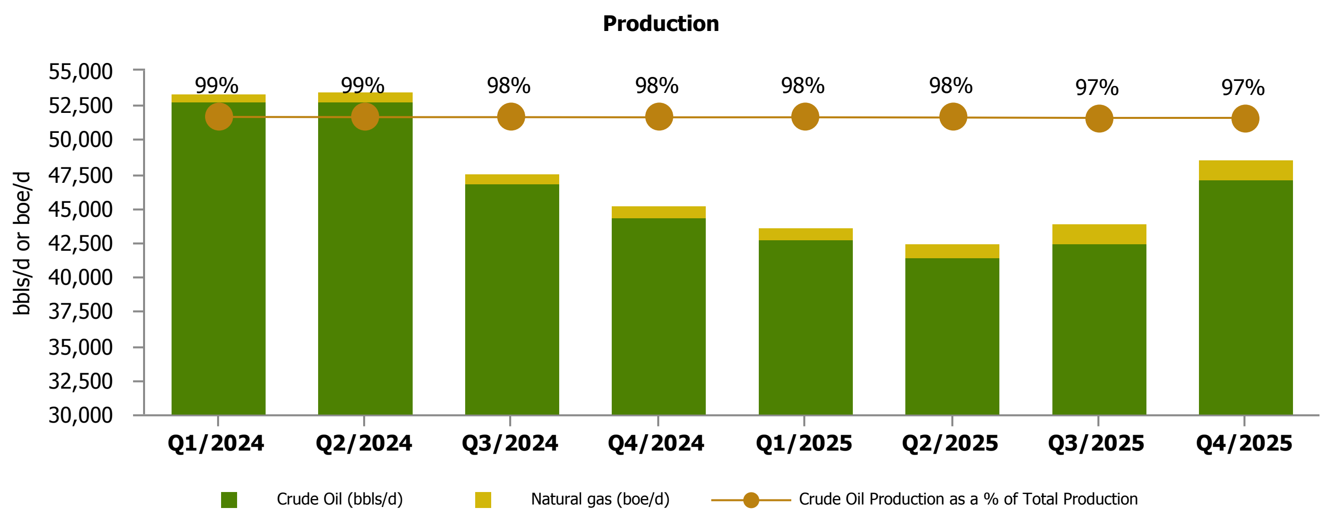
The increase in oil and natural gas production in the fourth quarter of 2025 compared to the fourth quarter of 2024 is mainly the result of new added production from Block LLA-74 and LLA-32 in the Southern Llanos Basin and an increase in gas production at VIM-1 in the Magdalena Basin. This was partially offset by decreased oil production from Block LLA-34 and the Cabrestero Block in the Southern Llanos Basin, mainly as a result of natural declines and a reduced level of development activity, consistent with lower capital spending. Production in the Northern Llanos Basin in the fourth quarter of 2025 was impacted by operational downtime on the Capachos Block, partially offset by increased production in Arauca.

The decrease in oil and natural gas production for full year 2025 compared to full year 2024 is mainly the result of natural declines and a reduced level of development activity at Block LLA-34 and the Cabrestero Block in the Southern Llanos Basin, consistent with lower capital spending. Production in the Northern Llanos Basin in 2025 decreased in the Arauca Block. These production declines were partially offset by newly added production from Block LLA-74 and LLA-32 in the Southern Llanos Basin and an increase in gas production at VIM-1 in the Magdalena Basin.

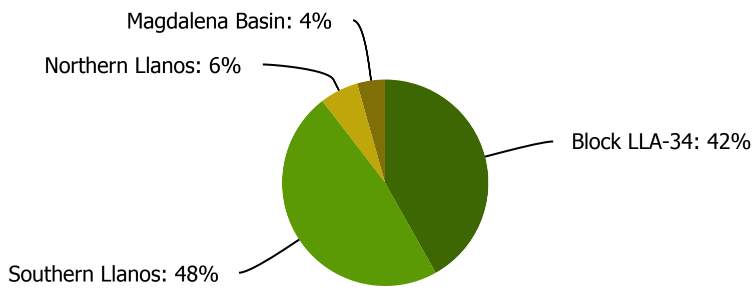
The increase in oil and natural gas production in the fourth quarter of 2025 compared to the third quarter of 2025 is mainly the result of new added production from Block LLA-74 and LLA-32 in the Southern Llanos Basin.

Oil and natural gas sales in the fourth quarter of 2025 were 47,389 boe/d compared to 47,385 boe/d for the fourth quarter of 2024.

Refer to "Consolidated Results of Operations" for annual production split by product type.



Production By Area
(Three Months ended December 31, 2025)



b) Crude Oil Reference and Realized Prices

Average price for the period	**Q4 2025**	Q3 2025	Q2 2025	Q1 2025	Q4 2024
Brent ($/bbl)	**63.08**	68.17	66.71	74.98	74.01
Parex location (Vasconia) and quality differential ($/bbl)	**(3.03)**	(1.94)	(1.87)	(2.26)	(5.16)
Parex wellhead sales discount ($/bbl)	**(3.35)**	(3.91)	(3.77)	(5.67)	(4.84)
Parex realized oil sales price ($/bbl)(2)	**56.70**	62.32	61.07	67.05	64.01
Parex realized price (differential) to Brent crude ($/bbl)	**(6.38)**	(5.85)	(5.64)	(7.93)	(10.00)
Parex transportation expense ($/bbl)(1)(2)	**(5.47)**	(4.88)	(4.58)	(4.34)	(3.96)
Parex price differential and transportation expense ($/bbl)(2)	**(11.85)**	(10.73)	(10.22)	(12.27)	(13.96)

(1) Applies only to direct export cargo sales where Parex incurs the pipeline fees directly. See "Transportation Expense".
(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

During the fourth quarter of 2025, the differential between Brent reference pricing and the Company's realized oil sale price was $6.38/bbl. The differential to Brent crude during the fourth quarter of 2025 increased by $0.53/bbl compared to the third quarter of 2025 where the differential was $5.85/bbl. Compared to the fourth quarter of 2024 Parex's realized price improved from a differential of $10.00/bbl to $6.38/bbl, which was mainly driven by improved location and quality differentials, due to narrower heavy oil differentials and reduced wellhead sales in favour of direct export sales.

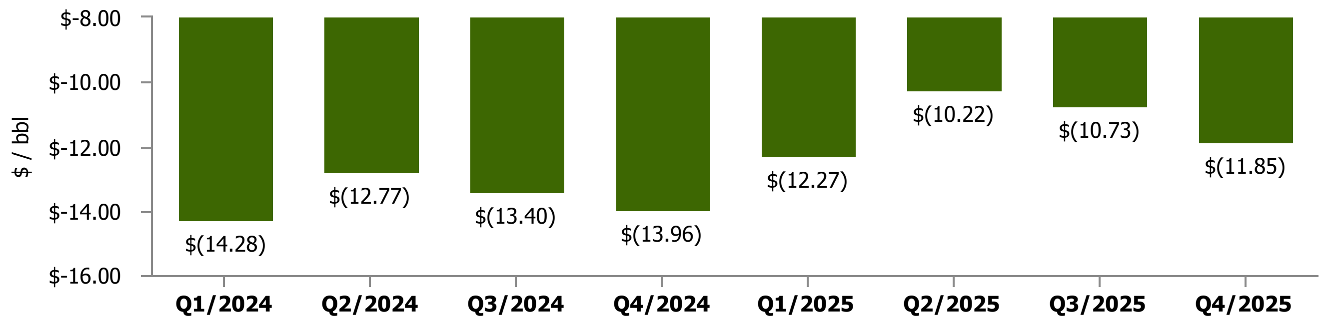
Differences between Parex's realized price and Brent crude price is mainly related to location and quality adjustments, wellhead sale marketing contracts, and the timing of oil sales compared to quarter averages. The location and quality differential between Brent crude pricing also affects Parex's realized sales price and is set in liquid global markets and therefore attributed to factors that are beyond the Company's control making it inherently difficult to forecast.

Parex's realized price differential to Brent crude can fluctuate period over period due to, among other factors, the type of sales contract and the accounting treatment for oil sold at the wellhead versus direct export sales contracts.

The fourth quarter 2025 differential of $3.03/bbl was an improvement from the fourth quarter 2024 differential of $5.16/bbl and was likely the result of market uncertainty regarding availability of medium/heavy crude oil specifically from Mexico and Venezuela, and tariff tensions impacting world crude pricing.

The Vasconia differential to Brent can fluctuate with oil market conditions and for the month of February 2026 was approximately $7.50/bbl, having widened significantly following ongoing macroeconomic volatility and expectations around incremental heavy oil supply.

Parex Realized Price Differential & Transportation Expense



c) Natural Gas Sales and Realized Prices

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Natural gas sales ($000s)	**$ 9,371**	$ 3,876	**$30,155**	$ 12,851
Realized sales price ($/Mcf)(1)	**11.29**	8.12	**11.68**	7.93

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Parex natural gas sales were $9.4 million and $30.2 million for the three months and year ended December 31, 2025 compared to $3.9 million and $12.9 million in the same periods of 2024. The increase in natural gas sales from the prior periods is primarily related to increased volumes sold from the Capachos and VIM-1 Blocks and increase in realized gas sales price.

d) Oil and Natural Gas Sales

In 2025 oil and natural gas sales decreased by $274.2 million or 21% as reconciled in the table below to 2024:

($000s)	
Oil and natural gas sales, year ended December 31, 2024	**$ 1,280,029**
Sales volume of produced oil, a decrease of 12% (6,007 bbl/d)	**(157,214)**
Sales volume of purchased oil, a decrease of 89% (25 bbl/d)	**(642)**
Sales price decrease of 12%	**(133,635)**
Sales volume and price change of produced natural gas	**17,304**
Oil and natural gas sales, year ended December 31, 2025	**$ 1,005,842**

Oil and natural gas sales decreased year over year mainly due to lower oil volumes sold and a decrease in world oil prices.

e) Crude Oil Inventory in Transit

As at December 31, ($000s)	**2025**	2024
Crude oil in transit	**$ 4,327**	$ 2,017

As at December 31, 2025, the Company had 116.9 mbbls (December 31, 2024 - 48.5 mbbls) of crude oil inventory in transit, which was injected into Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, transportation costs, depletion expense and royalty expense) at approximately $37/bbl ($42/bbl - 2024) incurred in bringing the crude oil to its existing condition and location.

A reconciliation of quarter-to-quarter crude oil inventory movements is provided below:

For the periods ended (mbbls)	**Dec. 31, 2025**	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025
Crude oil inventory in transit - beginning of the period	**4.9**	5.5	31.3	48.5
Oil production	**4,333.4**	3,914.7	3,780.6	3,857.1
Oil sales	**(4,221.4)**	(3,915.3)	(3,806.4)	(3,875.6)
Purchased oil	**—**	—	—	1.3
Crude oil inventory in transit (overlift) - end of the period	**116.9**	4.9	5.5	31.3
% of period production	**2.7**	0.1	0.1	0.8

Crude oil inventory build (and draw) from period to period are subject to factors that the Company does not control such as timing of the number of shipments from storage to export. The Company expects crude oil inventory in future periods to be in line with normal historic levels of below 5% of period production.

f) Purchased Oil

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Purchased oil expense ($000s)	**$ —**	$ 59	**$ 162**	$ 904

Purchased oil expense has decreased compared to the same periods of 2024 as a result of a decrease in oil blending operations and purchases of partner crude oil. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

g) Other Revenue

The Company's other revenue includes pipeline transportation revenue and revenue related to energy generation and use of infrastructure.

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Other revenue	**$ 2,827**	$ 2,739	**$ 9,826**	$ 8,157

Royalties

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Base royalties(1)	**$ 19,952**	$ 22,883	**$ 80,863**	$ 106,980
Economic rights(2)	**8,697**	18,211	**45,889**	94,438
Royalties ($000s)	**$ 28,649**	$ 41,094	**$ 126,752**	$ 201,418
Per unit ($/boe)(3)	**6.57**	9.43	**7.80**	10.99
Percentage of sales(3)	**12**	15	**13**	16

(1) Base royalties are sliding scale royalties based on field production and payable to the Colombian National Hydrocarbon Agency ("ANH"). Refer to the Company's AIF, which may be accessed through the SEDAR+ website at www.sedarplus.ca.
(2) Economic rights include high price share royalties applicable to production in excess of 5 million barrels of oil and X-Factor royalties are an additional royalty applicable to heavy oil production, both payable to ANH. Refer to the Company's AIF, which may be accessed through the SEDAR+ website at www.sedarplus.ca.
(3) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

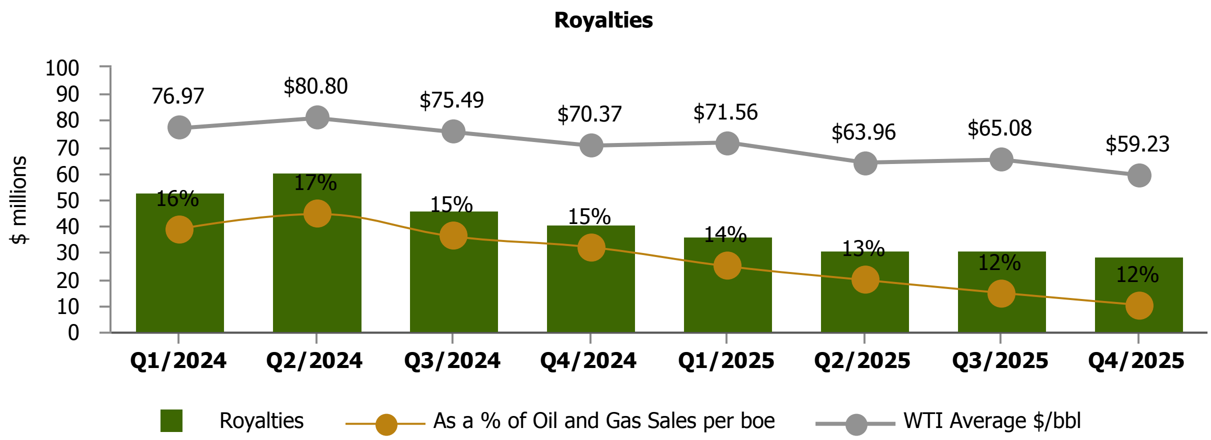
Royalty expense was $28.6 million and $126.8 million in the three months and year ended December 31, 2025, respectively, compared to $41.1 million and $201.4 million for the 2024 comparative periods.

Royalties as a percentage of sales were 12% and 13% in the three months and year ended December 31, 2025, respectively, compared to 15% and 16% for the 2024 comparative periods.

The decrease in royalty expense and royalties as a percentage of sales compared to 2024 was primarily attributable to lower production and a decrease in world oil prices in 2025. Royalties decreased in areas where high price share royalties are applicable as a result of lower production and Benchmark WTI prices.

Benchmark WTI prices are used in the high price share royalty ("HPR") calculation. Effectively higher realized WTI oil prices result in a higher royalty percentage realized. Benchmark WTI prices for the three months and year ended December 31, 2025 were $59.23 and $63.05 compared to $70.37 and $75.90 for the 2024 comparative periods and $65.08 in the third quarter of 2025.

For further information concerning the HPR please refer to the Company's AIF which may be accessed through the SEDAR+ website at www.sedarplus.ca where the calculation is described as a "High Price Share Royalty" in the "Industry Conditions - Colombia - High Price Participation" section.



Production Expense

		For the three months ended December 31,			For the year ended December 31,		
		2025		2024		**2025**		2024
Production expense ($000s)	**$**	**57,073**	$	67,708	**$**	**225,543**	$	255,278
Per unit ($/boe)(1)		**13.09**		15.53		**13.88**		13.93

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

A breakdown of the production expense on a per boe basis between operated and non-operated fields is provided below:

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Operated production expense per unit ($/boe)(1)	**10.79**	18.93	**13.07**	16.51
Non-operated production expense per unit ($/boe(1)	**16.42**	12.32	**14.82**	11.64

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Production expense for the three months and year ended December 31, 2025 was $13.09/boe and $13.88/boe compared to $15.53/boe and $13.93/boe for the three months and year ended December 31, 2024. Production expense for the third quarter of 2025 was $15.36/boe.

Operated properties production expense for the three months and year ended December 31, 2025 was $10.79/boe and $13.07/boe compared to $18.93/boe and $16.51/boe for the three months and year ended December 31, 2024. Operated properties production expense per boe decreased for the year ended December 31, 2025, compared to 2024, primarily due to increased production from development activities, the LLA-32 tuck-in acquisition and new production from LLA-74, which improved fixed cost absorption. Also during 2025 corporate efficiency initiatives were implemented to reduce fixed and variable production costs.

Non-operated properties production expense for the three months and year ended December 31, 2025 was $16.42/boe and $14.82/boe compared to $12.32/boe and $11.64/boe for the three months and year ended December 31, 2024. Non-operated properties production expense per boe has increased for the year ended December 31, 2025 compared to 2024 mainly as a result of decreased production resulting in reduced fixed cost absorption and the one-time non-recurring production cost adjustment that reflects a true-up to actual costs incurred to date for non-operated activities.

The table below provides a reconciliation of the increase in production expense per boe by main components:

	Q4 2025 vs Q3 2025	Q4 2025 vs Q4 2024	YTD 2025 vs YTD 2024
Comparative period production expense per boe(1)	**$ 15.36**	**$ 15.53**	**$ 13.93**
Power generation	**(1.26)**	**(2.39)**	**0.15**
Well workovers and facility maintenance	**(0.41)**	**(1.16)**	**(0.09)**
Colombian pesos ("COP") appreciation	**0.57**	**1.86**	**0.07**
Non-recurring non-operated production cost adjustment	**(0.89)**	**—**	**0.22**
Fixed cost absorption	**(0.45)**	**(1.05)**	**(0.31)**
Other variable costs	**0.17**	**0.30**	**(0.09)**
Current year production expense per boe(1)	**$ 13.09**	**$ 13.09**	**$ 13.88**

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

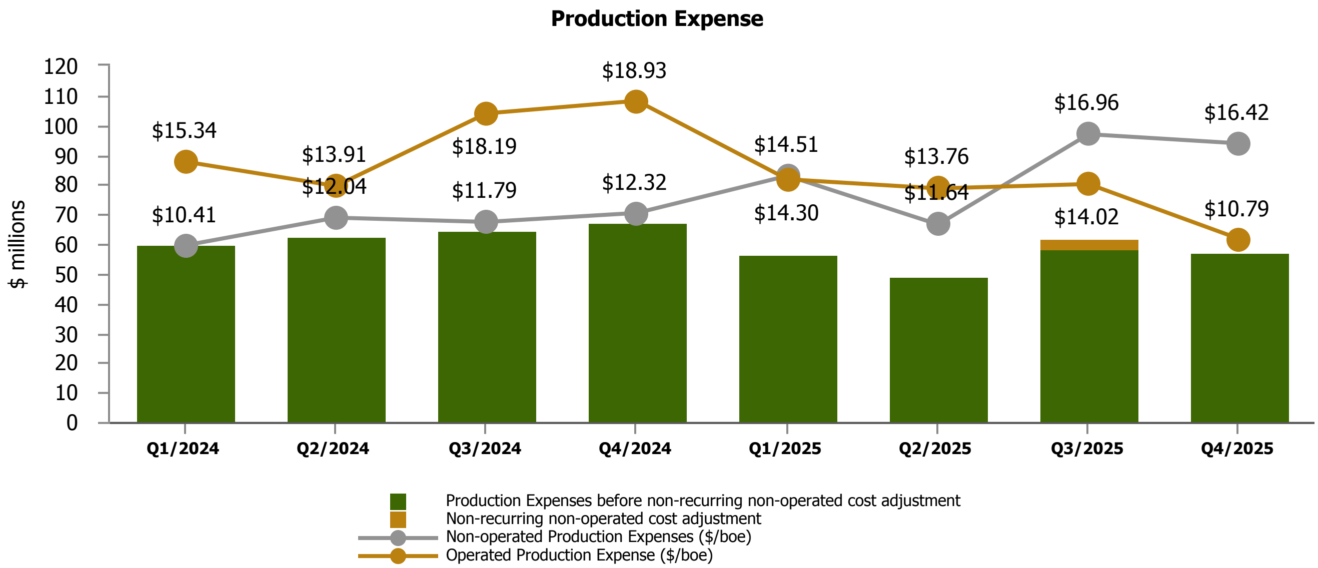
The decrease in production expense for the three months ended December 31, 2025 over the 2024 comparative period is mainly the result of lower electrical power costs used to power field operations, reduced well workovers and facility maintenance costs, and improved fixed costs absorption due to corporate efficiency initiatives that were implemented. In addition, higher production levels allowed fixed and variable costs to be spread over more production, reducing the per-boe cost. These decreases were partially offset by the appreciation of the COP.

The decrease in production expense for the year ended December 31, 2025 over the 2024 comparative period is mainly the result of improved fixed costs absorption due to corporate efficiency initiatives that were implemented and lower well workovers and facility maintenance costs. This was partially offset by higher electrical power costs used to power field operations, the one-time nonrecurring non-operated production cost adjustment and the appreciation of the COP.

Compared to the third quarter of 2025, fourth quarter 2025 production expense per boe has decreased due to lower electrical power costs, reduced well workovers and facility maintenance costs, a reduction in non-operated production costs and improved fixed cost absorption, partially offset by the appreciation of the COP.

Colombia's electricity grid is heavily reliant on hydroelectric power which exposes the Company to fluctuations in power prices due to changes in rainfall and water reservoir levels, as well as electricity supply and demand. During 2024, Colombia experienced an El Niño-induced drought that led to an escalation in power costs across the country. During the first quarter of 2025 power costs began to decrease due to more rainfall in the country, which replenished reservoirs used for hydroelectric power generation, causing power costs to decrease substantially for the remainder of the year. Currently, power costs have declined from the elevated levels seen in late 2024 and are more in line with historical norms.

Production expense per boe is estimated to be approximately $13-16/boe during 2026 per the guidance provided on January 19, 2026.



Transportation Expense

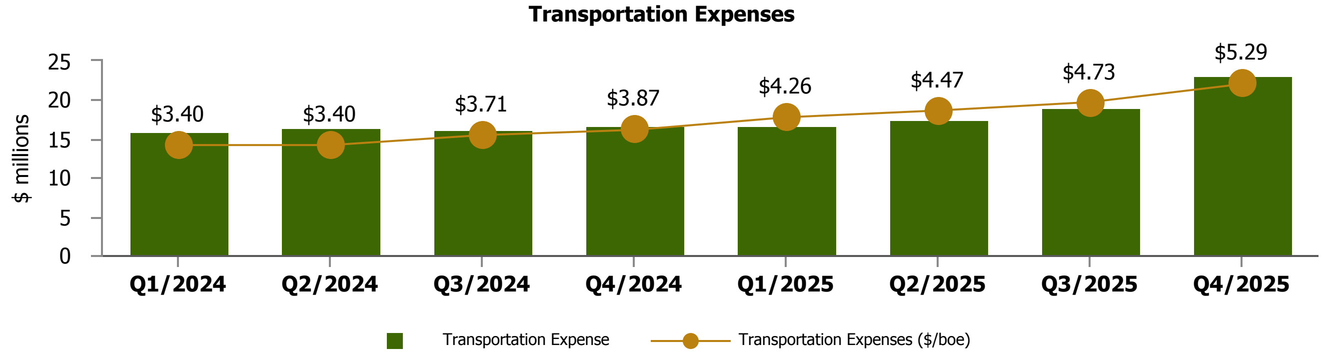
	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Transportation expense ($000s)	**$ 23,081**	$ 16,877	**$ 76,444**	$ 65,745
Per unit ($/boe)(1)	**5.29**	3.87	**4.70**	3.58

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility and pipeline tariffs.

For the three months ended December 31, 2025, transportation expense of $5.29/boe increased from $4.73/boe for the third quarter of 2025 and $3.87/boe for the comparative period in 2024. On a year-to-date basis transportation expense was $4.70/boe compared to $3.58/boe in the comparative period in 2024. Transportation expense increased due to an increase in oil volumes transported by truck, higher gas volumes transported from increased gas production at the Capachos and VIM-1 Blocks, and the appreciation of the Colombian peso. The higher trucked oil volumes are associated with additional production from Azogue on Block LLA-32 and new production from Block LLA-74. Transportation expense will fluctuate period over period due the mix of sales contracts types in force during the period.

The combined transportation expense and price differential from Brent for the fourth quarter of 2025, on a per boe basis, has decreased from the fourth quarter of 2024 and increased from the third quarter of 2025. See "Crude Oil Reference and Realized Prices".



General and Administrative Expense ("G&A")

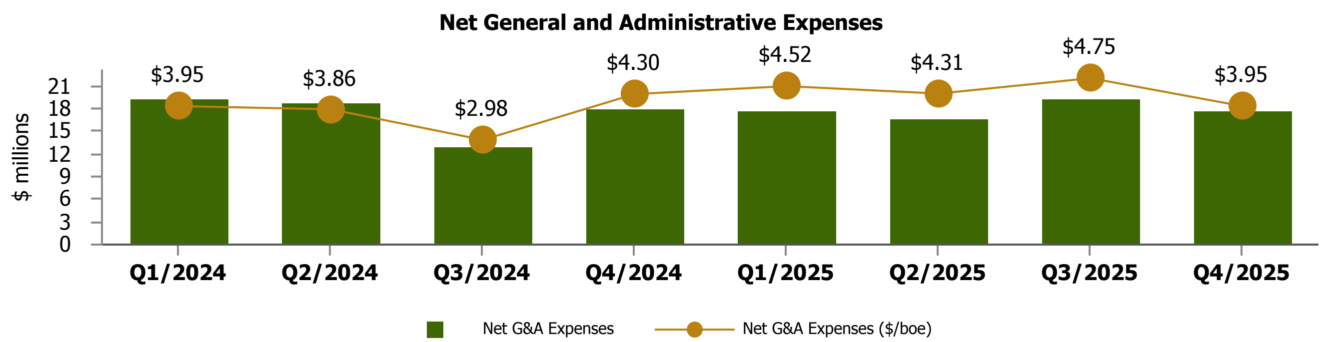
	For the three months ended December 31,				For the year ended December 31,			
($000s)		**2025**		2024		**2025**		2024
Gross G&A	**$**	**23,648**	$	21,650	**$**	**87,779**	$	81,288
G&A recoveries		**(1,985)**		(879)		**(5,642)**		(3,796)
Capitalized G&A		**(4,006)**		(2,871)		**(10,811)**		(8,584)
Net G&A expense	**$**	**17,657**	$	17,900	**$**	**71,326**	$	68,908
Per unit ($/boe) (1)		**3.95**		4.30		**4.37**		3.77

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Net G&A was $17.7 million and $71.3 million for the three months and year ended December 31, 2025 compared to $17.9 million and $68.9 million for the same periods in 2024. Gross G&A was $23.6 million and $87.8 million for the three months and year ended December 31, 2025 (three months and year ended December 31, 2024 - $21.7 million and $81.3 million).

On a per boe basis net G&A in 2025 increased by 16% to $4.37 from $3.77 in 2024 mainly as a result of lower production resulting in increased per boe costs.

The Company's G&A expense is mainly denominated in local currencies of COP and Canadian dollars ("Cdn") which as they appreciate/ depreciate have an impact on G&A expense. Refer to the "Foreign Exchange Sensitivity Analysis" for further information.



Share-Based Compensation

($000s)	For the three months ended December 31, 2025	2024	For the year ended December 31, 2025	2024
Equity settled share-based compensation expense	**$ 183**	$ 223	**$ 714**	$ 878
Cash settled share-based compensation expense	**9,863**	5,926	**29,802**	584
Total share-based compensation expense	**$ 10,046**	$ 6,149	**$ 30,516**	$ 1,462

Share-based compensation expense was $10.0 million and $30.5 million for the three months and year ended December 31, 2025 compared to $6.1 million and $1.5 million for the same periods in 2024.

Equity settled share-based compensation expense was $0.2 million and $0.7 million for the three months and year ended December 31, 2025 compared to $0.2 million and $0.9 million for the same periods in 2024. Equity settled share-based compensation includes the Company's stock option plan.

Cash settled share-based compensation relates to the Company's cash settled incentive plans and includes cash settled restricted share units ("CRSUs"), cash or share settled restricted share units and performance share units ("CosRSUs" and "CosPSUs"), long duration restricted share units and performance share units ("LDRSUs and "LDPSUs"), and deferred share units ("DSUs"). Cash settled share-based compensation expense for the three months and year ended December 31, 2025 was $9.9 million and $29.8 million compared to $5.9 million and $0.6 million for the same periods in 2024. This increase in expense is mainly attributable to the increase in Parex's share price from period end dates. Parex share price increased to Cdn$18.45 at December 31, 2025 from Cdn$14.58 at December 31, 2024.

Obligations for payments of cash under the Company's cash settled incentive plans are accrued as expense over the vesting period based on the fair value of the units as described in note 21 - Cash Settled Incentive Plans of the audited consolidated financial statements. As at December 31, 2025, the total cash settled incentive plans liability accrued was $37.6 million (December 31, 2024 - $19.9 million) of which $15.2 million (December 31, 2024 - $9.6 million) is classified as long-term in accordance with the vesting periods.

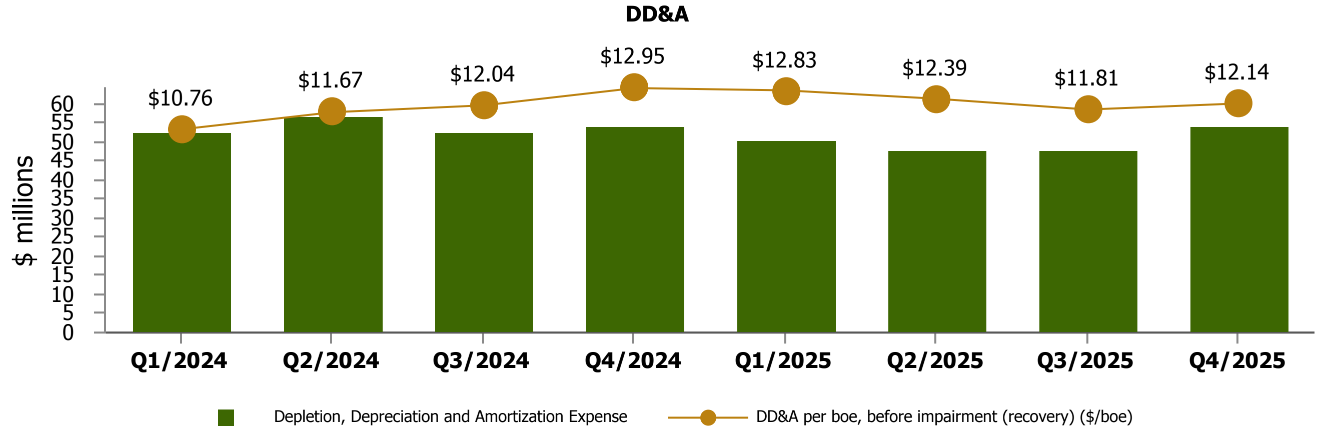
Cash payments to settle cash settled share-based compensation in the three months and year ended December 31, 2025 were $0.5 million and $12.8 million compared to $0.3 million and $20.6 million for the same periods in 2024.

Depletion, Depreciation and Amortization Expense ("DD&A")

	For the three months ended December 31, 2025	2024	For the year ended December 31, 2025	2024
DD&A ($000s) total	**$ 54,270**	$ 53,984	**$ 200,405**	$ 215,770
Per unit ($/boe)[1]	**12.14**	12.95	**12.28**	11.81

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

For the year ended December 31, 2025, DD&A was $200.4 million ($12.28/boe) as compared to $215.8 million ($11.81/boe) for the prior year. The increase per boe from the prior year period is due to adding to the depletable base through capital expenditures made during 2025 and the transfer of Block LLA-74 partially offset by lower production.



Foreign Exchange

		For the three months ended December 31,			For the year ended December 31,		
($000s)		**2025**		2024		**2025**	2024
Foreign exchange (gain) loss	**$**	**(961)**	$	2,194	**$**	**(1,934)** $	5,447
Foreign currency risk management contracts gain		**(1,128)**		—		**(8,998)**	—
Total foreign exchange (gain) loss	**$**	**(2,089)**	$	2,194	**$**	**(10,932)** $	5,447
Average foreign exchange rates							
USD$/Cdn$		**1.39**		1.40		**1.40**	1.37
USD$/COP		**3,819**		4,347		**4,053**	4,071

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Cdn and COP, as the Company's functional currency is the U.S. dollar ("USD"). The Company has exposure in Colombia and Canada on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The main drivers of foreign exchange gains and losses recorded on the consolidated statements of comprehensive income is the COP denominated income tax payable and tax withholdings receivable, accounts payable and accounts receivable. The timing of payment settlements, accruals and their adjustments have impacts on foreign exchange gains/losses.

For the three months and year ended December 31, 2025, a total foreign exchange gain of $2.1 million and $10.9 million was recorded compared to a loss of $2.2 million and $5.4 million in the respective prior year periods.

For the three months and year ended December 31, 2025, the Company also recorded a $4.6 million and $9.0 million realized gain on a COP/USD collar which settled in the money and is included in the total foreign exchange (gain) loss in the consolidated statement of comprehensive income for the year ended December 31, 2025.

Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company's consolidated statements of comprehensive income.

The Company reviews its exposure to foreign currency variations on an ongoing basis and maintains cash deposits primarily denominated in USD and COP in Canada, Switzerland and Colombia.

Foreign Exchange Sensitivity Analysis

Cost component	Estimated percent of cost denominated in local currency	$/boe Impact of change in local currency/ $USD exchange rate	
		10% appreciation of local currency	10% depreciation of local currency
Production expense	90%	$ 1.18	$ (1.18)
Transportation expense	50%	$ 0.26	$ (0.26)
G&A expense	100%	$ 0.40	$ (0.40)

The table above displays the estimated per boe impact of a change in Parex's local currencies and the effect on Parex's key cost components. The component impact in $/boe terms uses Q4 2025 per boe costs. This analysis ignores all other factors impacting cost structure including, but not limited to, efficiencies, cost reduction strategies, and cost inflation.

As at December 31, 2025, with other variables unchanged, the impact on the Company's financial instruments of a 10% strengthening (weakening) of the Cdn and COP against the USD would have decreased (increased) net income by approximately $8.7 million.

Other Expense

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Other Colombian taxes	**$ 2,752**	$ 355	**$ 8,850**	$ 1,611
Colombian tax credit purchased	**—**	—	**8,097**	—
Legal provisions	**8,625**	—	**8,625**	—
Loss on settlement of decommissioning liabilities	**(392)**	1,127	**147**	1,593
Loss on disposition of tangible assets	**419**	649	**500**	1,987
Other	**381**	77	**2,981**	1,036
Total other expense	**$ 11,785**	$ 2,208	**$ 29,200**	$ 6,227

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Non-cash other expense	**$ 8,652**	$ 1,776	**$ 9,272**	$ 3,580
Cash other expense	**3,133**	432	**19,928**	2,647
Total other expense	**$ 11,785**	$ 2,208	**$ 29,200**	$ 6,227

Other expense is comprised mainly of other Colombian taxes including the 1% surcharge on the sale or export of crude oil effective for 2025, legal provisions, Colombian tax credit purchased to reduce income tax expense, loss (gain) on settlement of decommissioning liabilities and loss (gain) on settlement of tangible assets. The non-cash components of other expense include the legal provisions, loss (gain) on settlement of decommissioning liabilities and loss (gain) on settlement of tangible assets.

Legal provisions have been recognized in respect of estimated fines and penalties mainly arising from environmental regulatory disputes. Management has assessed the likelihood of settlement and determined the best estimate based on relevant legislation and the probability of enforcement outcomes. The timing of the outflows is expected within 10 years. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

Net Finance Expense

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Bank charges and credit facility fees	**$ 911**	$ 1,124	**$ 4,748**	$ 3,673
Interest on bank debt	**1,100**	700	**2,765**	4,174
Accretion on decommissioning and environmental liabilities	**2,473**	1,848	**9,122**	9,206
Interest and other income	**(1,154)**	(998)	**(4,369)**	(4,315)
Bad debt expense	**—**	—	**3,442**	—
Expected credit loss (recovery) provision	**87**	163	**(53)**	67
Lease obligation interest expense	**224**	46	**365**	189
Other	**281**	437	**1,013**	1,099
Net finance expense	**$ 3,922**	$ 3,320	**$ 17,033**	$ 14,093

	For the three months ended December 31,		For the year ended December 31,	
	2025	2024	**2025**	2024
Non-cash finance expense	**$ 2,560**	$ 2,012	**$ 12,511**	$ 9,273
Cash finance expense	**1,362**	1,308	**4,522**	4,820
Net finance expense	**$ 3,922**	$ 3,320	**$ 17,033**	$ 14,093

Bank charges and credit facility fees relate to bank taxes paid in Colombia and the standby fees related to the Company's credit facility. The non-cash components of net finance expense include the accretion on decommissioning and environmental liabilities, bad debt expense and the expected credit loss (recovery) provision.

Risk Management

Management of cash flow variability is an integral component of Parex's business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the board of directors ("the Board" or "Board of Directors") to establish risk management guidelines to be used by management. The risk exposure inherent in movements in the price of crude oil, fluctuations in the USD/COP exchange rate and interest rate movements are all proactively reviewed by Parex and as considered appropriate may be managed through the use of derivatives primarily with financial institutions that are members of Parex's syndicated bank credit facility. The Company considers these derivative contracts to be an effective means to manage and forecast cash flow.

Parex has elected not to apply IFRS prescribed "hedge accounting" rules and, accordingly, pursuant to IFRS the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity and foreign exchange forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period-ending commodity and foreign exchange forward strip prices, in respect of any outstanding commodity or foreign exchange derivative contracts.

a) Risk Management Contracts – Brent Crude

As at December 31, 2025, the Company had no commodity price risk management contracts in place.

The following is a summary of the commodity price risk management contracts entered into subsequent to December 31, 2025:

Period Hedged	Reference	Volume bbls/d	Call strike price	Put Strike	Low Put Strike	Premium
January 1, 2026 to January 31, 2026	ICE Brent	12,000	$70.00	$60.00	$55.00	$0.65
April 1, 2026 to April 30, 2026	ICE Brent	12,000	$70.00	$60.00	$53.00	$—
May 1, 2026 to May 31, 2026	ICE Brent	12,000	$70.00	$60.00	$53.00	$—
June 1, 2026 to June 30, 2026	ICE Brent	12,000	$70.00	$60.00	$53.00	$—

The table below summarizes the loss (gain) on the commodity risk management contracts that were in place during the three months and years ended December 31, 2025 and 2024:

($000s)	For the three months ended December 31, **2025**	2024	For the year ended December 31, **2025**	2024
Realized gain on commodity risk management contracts	**$ (2,019)**	$ —	**$ (5,356)**	$ —
Premiums paid on commodity risk management contracts	**1,212**	—	**7,935**	—
Unrealized (gain) loss on commodity risk management contracts	**172**	1,160	**(1,160)**	1,160
Total	**$ (635)**	$ 1,160	**$ 1,419**	$ 1,160

b) Risk Management Contracts – Foreign Exchange

The Company is exposed to foreign currency risk as various portions of its cash balances are held in COP and Cdn while its committed capital expenditures are expected to be primarily denominated in USD.

As at December 31, 2025, the Company had no foreign currency risk management contracts in place.
The following is a summary of the foreign currency risk management contracts entered into subsequent to December 31, 2025:

Period Hedged	**Reference**	**Currency Option Type**	**Amount USD**	**Strike Price COP**	**Max compensation**
January 16, 2026 to December 15, 2026	COP	Collar with limited compensation	$99,000,000	3,700-4,200	800

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three months and years ended December 31, 2025 and 2024:

($000s)	For the three months ended December 31, **2025**	2024	For the year ended December 31, **2025**	2024
Unrealized loss on foreign currency risk management contracts	**$ 3,452**	$ —	**$ —**	$ —
Realized gain on foreign currency risk management contracts	**(4,580)**	—	**(8,998)**	—
Total	**$ (1,128)**	$ —	**$ (8,998)**	$ —

Marketable securities

	December 31, 2025	December 31, 2024
Marketable securities	**$ 45,090**	$ —

In 2025, the Company acquired 6,084,986 common shares (the "GeoPark Shares") of GeoPark Ltd (NYSE: GPRK), representing approximately 11.8% ownership, for aggregate consideration of $40.5 million ($6.65 per share). The fair value of the GeoPark Shares at December 31, 2025 was $45.1 million, resulting in an unrealized gain of $4.6 million, which is recorded in the consolidated statement of comprehensive income.

Parex is exposed to market risk associated with its marketable securities, including the GeoPark Shares, primarily driven by changes in the market price and liquidity of the securities. The market price of the GeoPark Shares may be volatile and could be adversely affected by general market conditions, the investee's performance and disclosures, oil and gas commodity prices, interest and foreign exchange rates, geopolitical developments in the investee's areas of operation, and other factors beyond the Company's control.

Total Non-Current Financial Liabilities

The following table summarizes the total non-current financial liabilities for the three most recently completed financial years:

	2025	2024	2023
Bank debt	**$ 33,000**	$ 60,000	$ 90,000
Lease obligation	**7,814**	4,622	5,736
Cash settled share-based compensation liabilities	**15,228**	9,553	16,284
Other long-term liabilities	**7,143**	—	—
Total	**$ 63,185**	$ 74,175	$ 112,020

Income Tax

The components of tax (recovery) expense for the three months and year ended December 31, 2025 and 2024 were as follows:

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2025**	2024	**2025**	2024
Current tax expense (recovery)	**$ 1,235**	$ (5,629)	**$ 33,502**	$ 90,389
Deferred tax (recovery) expense	**(41,313)**	4,749	**(53,779)**	158,203
Total tax (recovery) expense	**$ (40,078)**	$ (880)	**$ (20,277)**	$ 248,592
Effective current tax rate on funds flow provided by operations before tax(1)	**1%**	(4)%	**7%**	13%

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Current tax in the fourth quarter of 2025 was an expense of $1.2 million as compared to a $5.6 million recovery in the comparative three-month period. For the full year 2025 the Company recorded $33.5 million of current tax expense as compared to $90.4 million in 2024.

The significant decrease in current tax expense from the 2024 comparative periods is the result of lower operating cash flows before tax, along with certain tax strategies that have been deployed over recent years.

For the three months and year ended December 31, 2025, deferred tax was a recovery of $41.3 million and $53.8 million compared to an expense of $4.7 million and $158.2 million for the three months and year ended December 31, 2024. The increase in deferred tax recovery from the 2024 comparative periods is mainly a result of the appreciation of the Colombian peso and the reversal of the temporary differences created between the accounting and tax basis in Colombia.

2026 Current Tax Guidance

The table below reflects the expected effective current tax rate on funds flow provided by operations before tax in 2026:

Brent price assumption	**$60/bbl**	**$65/bbl**	**$70/bbl**	**$75/bbl**
Effect current tax rate on before tax funds flow provided by operations(1)	1-3%	4%	5-7%	8-11%

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

The calculation of current and deferred income tax in Colombia is based on a number of variables which can cause swings in current and deferred income tax. These variables include but are not limited to the year-end producing reserves used in calculating depletion for tax purposes, the timing and number of dry hole write-offs permissible for Colombian tax purposes and currency fluctuations.

Capital Expenditures

For the year ended December 31, ($000s)	Colombia 2025	Colombia 2024	Canada 2025	Canada 2024	Total 2025	Total 2024
Acquisition of unproved properties	**$ 9,937**	$ 2,619	**$ —**	$ —	**$ 9,937**	$ 2,619
Geological and geophysical	**10,101**	9,950	**—**	—	**10,101**	9,950
Drilling and completion	**248,507**	263,629	**—**	—	**248,507**	263,629
Well equipment and facilities	**38,618**	67,239	**—**	—	**38,618**	67,239
Other	**1,822**	438	**1,340**	3,820	**3,162**	4,258
Total capital expenditures(1)	**$ 308,985**	$ 343,875	**$ 1,340**	$ 3,820	**$ 310,325**	$ 347,695

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

For the three months ended December 31, ($000s)	Colombia 2025	Colombia 2024	Canada 2025	Canada 2024	Total 2025	Total 2024
Acquisition of unproved properties	**$ 4,791**	$ 941	**$ —**	$ —	**$ 4,791**	$ 941
Geological and geophysical	**1,100**	6,819	**—**	—	**1,100**	6,819
Drilling and completion	**62,581**	53,056	**—**	—	**62,581**	53,056
Well equipment and facilities	**14,212**	17,502	**—**	—	**14,212**	17,502
Other	**1,135**	438	**801**	3,354	**1,936**	3,792
Total capital expenditures(1)	**$ 83,819**	$ 78,756	**$ 801**	$ 3,354	**$ 84,620**	$ 82,110

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Below is additional information related to capital expenditures in the period by key operating area:

($000s)	For the three months ended December 31, 2025	For the three months ended December 31, 2024	For the year ended December 31, 2025	For the year ended December 31, 2024
Block LLA-34	**$ 10,598**	$ 15,447	**$ 48,201**	$ 87,821
Southern Llanos	**33,176**	37,990	**190,241**	120,434
Northern Llanos	**11,148**	22,863	**32,297**	119,685
Putumayo Basin	**14,842**	—	**18,075**	—
Magdalena Basin	**12,919**	2,456	**18,348**	15,935
Canada and Colombia - Corporate	**1,937**	3,354	**3,163**	3,820
Total capital expenditures(1)	**$ 84,620**	$ 82,110	**$ 310,325**	$ 347,695

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".

During the year ended December 31, 2025, the Company incurred $310.3 million of capital expenditures with 92% spent on drilling, completion, well equipment and facilities in Colombia. During the year ended December 31, 2024, the Company incurred $347.7 million of capital expenditures with 95% spent on drilling, completion, well equipment and facilities in Colombia.

During the fourth quarter of 2025 the Company incurred capital expenditures of $84.6 million with 91% spent on drilling, completion, well equipment and facilities in Colombia. During the fourth quarter of 2024 the Company incurred capital expenditures of $82.1 million with 86% spent on drilling, completion and well equipment and facilities in Colombia.

During the year ended December 31, 2025, the Company's capital expenditures of $310.3 million were self-funded from funds flow provided by operations of $455.0 million.

Property Acquisition

On March 14, 2025, Parex, through a foreign subsidiary, acquired an additional 25% working interest in the Azogue field in the LLA-32 Block and 12.5% working interest in the remainder of the LLA-32 Block (the "LLA-32 Acquisition") resulting in 100% working interest in the Block for the Company. The Company paid total net consideration of $16.0 million.

The consolidated statement of comprehensive income includes results of operation of the LLA-32 Acquisition since the closing date of March 14, 2025. There were no transaction costs associated with the LLA-32 Acquisition.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed		
PP&E	$	16,788
Decommissioning liabilities		(820)
	$	15,968

Consideration for the acquisition		
Purchase price	$	19,000
Purchase price adjustments		(3,032)
Net consideration	$	15,968
Cash paid	$	14,970
Working capital adjustments		998
Total consideration paid	**$**	**15,968**

No working capital was included in the assets acquired.

The pro forma results for the year ended December 31, 2025 are shown below, as if the LLA-32 Acquisition had occurred on January 1, 2025. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	$	1,009,605
Net revenue less direct costs	$	580,120

The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. The consolidated statement of comprehensive income for the year ended December 31, 2025 includes $32.6 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the year ended December 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is $22.0 million. Net income for the year ended December 31, 2025 attributable to the assets acquired since the LLA-32 Acquisition is considered impracticable to calculate.

Long-Term Inventory

The Company has long-lead material and equipment inventory such as drill casing, natural gas compressors, and other major equipment. With, at times, strong demand for material and equipment used in oil and gas operations, periodically the Company secures material and equipment ahead of its upcoming capital programs. The Company plans on deploying this long-lead inventory over the coming years.

During 2025, the Company completed an impairment review of its long-term inventory. It was determined that the carrying amount of certain long-term inventory assets was lower than the recoverable amount and an impairment of $6.5 million (three months ended December 31, 2024 - $10.0 million) was recorded in the consolidated statements of comprehensive income for the three-month period ended December 31, 2025 .

Cost		
Balance at December 31, 2023	**$**	**204,701**
Additions		55,990
Transfers to E&E and PP&E assets		(40,028)
Transfer to production costs		(5,269)
Sale of inventory		(5,920)
Impairment		(10,000)
Balance at December 31, 2024	**$**	**199,474**
Additions		10,441
Transfers to E&E and PP&E assets		(25,045)
Transfer to production costs		(1,787)
Sale of inventory		(1,187)
Impairment		(6,470)
Balance at December 31, 2025	**$**	**175,426**

The below table represents the long-term inventory expenditures for the three months and years ended December 31, 2025 and 2024:

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2025**	2024	**2025**	2024
Additions	**$ 863**	8,189	**$ 10,441**	$ 55,990
Transfers to D&P and E&E assets	**(8,263)**	(6,941)	**(25,045)**	(40,028)
Transfer to production costs	**211**	(1,642)	**(1,787)**	(5,269)
Sale of inventory	**(489)**	(2,175)	**(1,187)**	(5,920)
Total long-term inventory expenditures, net of transfers and sales	**$ (7,678)**	$ (2,569)	**$ (17,578)**	$ 4,773

Non-Cash Impairment Charges

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2025**	2024	**2025**	2024
Impairment of E&E assets	**$ 11,140**	$ 49,424	**$ 11,140**	$ 54,085
Impairment of PP&E assets	**—**	78,417	**—**	78,417
Impairment of long-term inventory	**6,470**	10,000	**6,470**	10,000
Total non-cash impairment charges before deferred income tax recoveries	**$ 17,610**	$ 137,841	**$ 17,610**	$ 142,502

2025 Impairments

During 2025, the Company completed impairment reviews of its E&E assets. It was determined that the carrying amount of certain E&E assets wouldn't be recovered, primarily associated with the LLA-94 Block, for costs related to exploration wells which indicated non-economic results and has relinquished the block. It was determined that the impairment was $11.1 million which is recorded in the consolidated statements of comprehensive income for the year ended December 31, 2025.

The carrying amounts of the Company’s PP&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. At December 31, 2025, there were no indicators of PP&E impairment noted or indicators requiring a reversal of previously recorded impairments.

During 2025, the Company completed impairment reviews of its long-term inventory. It was determined that the carrying amount of certain long-term inventory assets was lower than the recoverable amount and an impairment of $6.5 million was recorded in the consolidated statements of comprehensive income for the three-month period ended December 31, 2025.

2024 Impairments

During 2024, the Company completed impairment reviews of its E&E assets. It was determined that the carrying amount of certain E&E assets wouldn't be recovered, primarily associated with the LLA-122 Block, for costs related to an exploration well which indicated technically unfeasible results at an acceptable risk tolerance. The impairment review compared the carrying value of the assets to the fair value less cost of disposal to determine the recoverable amount which was determined to be $nil for LLA-122 Block assets. It was determined that the impairment was $49.4 million and $54.1 million for the three months and year ended December 31, 2024, which is recorded in the consolidated statements of comprehensive income for the year ended December 31, 2024.

The carrying amounts of the Company’s PP&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. A revision of the estimation of the total proved and probable reserves in the Aguas Blancas CGU and the Boranda/Fortuna CGU, both in the Magdalena Basin, for the year ended December 31, 2024, evidenced a decline as compared to the prior year estimation. Management considered this to be an indicator of impairment and carried out an impairment review of these CGUs.

The Company determined that the carrying amount of Aguas Blancas CGU and the Boranda/Fortuna CGU exceeded their recoverable amounts and an impairment of $78.4 million was recorded in the consolidated statements of comprehensive income for the three months and year ended December 31, 2024. There are no E&E assets associated with these CGUs.

At December 31, 2024, the recoverable amount of the Aguas Blancas CGU was estimated to be $20.9 million, and the recoverable amount of the Boranda/Fortuna CGU was estimated to be $3.5 million. A 1% change to the assumed discount rate or a 5% change in forward price estimates over the life of the reserves would have an immaterial impact on the impairment. The fair value as determined was consistent with the Company's independent qualified reserve evaluators reserve estimate at December 31, 2024. The recoverable amount was determined using estimated fair value less costs of disposal.

Future cash flows were discounted using an after tax-rate of 14% with the following prices being used by Parex’s independent reserve evaluator as at December 31, 2024:

	2025	2026	2027	2028	2029	Thereafter
Brent ($US/bbl)	75.25	77.50	80.08	82.69	84.34	2% increase per year
WTI ($US/bbl)	71.25	73.50	76.00	78.53	80.10	2% increase per year

For all other CGUs, at December 31, 2024, there were no indicators of PP&E impairment noted or indicators requiring a reversal of previously recorded impairments.

During 2024, the Company completed impairment reviews of its long-term inventory. It was determined that the carrying amount of certain long-term inventory assets was lower than the recoverable amount and an impairment of $10.0 million was recorded in the consolidated statements of comprehensive income for the three-month period ended December 31, 2024.

For further information regarding the impairment charges for the years ended December 31, 2025 and 2024, refer to note 8 - Exploration and Evaluation Assets, note 9 - Property, Plant and Equipment and note 10 - Long-Term Inventory in the audited consolidated financial statements.

Impairment Test of Goodwill

The Company performed its annual test for goodwill impairment at the balance sheet date in accordance with its policy described in note 3 - Summary of Material Accounting Policies of the audited consolidated financial statements. The Company has allocated goodwill to the Colombia operating segment. The estimated fair value less costs of disposal of the Colombia operating segment exceeded the carrying value. As a result, no goodwill impairment was recorded. For additional information refer to note 14 - Goodwill in the audited consolidated financial statements.

Summary of Quarterly Results (unaudited)

Three months ended ($000s) (except per share amounts)	**Dec. 31, 2025**	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	**14,835**	10,525	10,498	10,650
Heavy Crude Oil (bbl/d)	**32,267**	32,026	31,047	32,207
Crude Oil (bbl/d)	**47,102**	42,551	41,545	42,857
Conventional Natural Gas (mcf/d)	**9,024**	8,412	5,982	4,806
Total (boe/d)	**48,606**	43,953	42,542	43,658
Realized sales price - oil ($/bbl)(6)	**56.70**	62.32	61.07	67.05
Financial (000s except per share amounts)				
Oil and natural gas sales	**$ 248,713**	$ 252,424	$ 239,070	$ 265,635
Funds flow provided by operations(5)	**$ 122,922**	$ 105,298	$ 104,821	$ 121,944
Per share – basic(2)(4)	**1.28**	1.09	1.08	1.24
Per share – diluted(2)(4)	**1.28**	1.09	1.08	1.24
Net income	**$ 74,865**	$ 50,476	$ 49,113	$ 80,629
Per share – basic(4)	**0.78**	0.52	0.50	0.82
Per share – diluted(4)	**0.78**	0.52	0.50	0.82
Dividends paid	**26,853**	26,892	27,561	26,365
Per share – Cdn$(4)(6)	**0.385**	0.385	0.385	0.385
Capital Expenditures(1)	**$ 84,620**	$ 79,961	$ 88,690	$ 57,054
Long-term inventory expenditures, net of transfers and sales	**$ (7,678)**	$ (1,585)	$ (3,667)	$ (4,648)
Total assets (end of period)	**$ 2,341,092**	$ 2,260,531	$ 2,223,178	$ 2,197,955
Outstanding shares (end of period) (000s)	**95,974**	96,564	97,184	97,814
Working capital (deficit) surplus (end of period)(3)(5)	**$ 28,027**	$ (3,167)	$ 20,048	$ 69,040

Three months ended ($000s) (except per share amounts)	Dec. 31, 2024	Sep. 30, 2024	Jun. 30, 2024	Mar. 31, 2024
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	9,550	9,064	9,541	7,237
Heavy Crude Oil (bbl/d)	34,882	37,777	43,229	45,543
Crude Oil (bbl/d)	44,432	46,841	52,770	52,780
Conventional Natural Gas (mcf/d)	5,190	4,368	4,788	3,348
Total (boe/d)	45,297	47,569	53,568	53,338
Realized sales price - oil ($/bbl)(6)	64.01	69.07	75.69	71.02
Financial (000s except per share amounts)				
Oil and natural gas sales	$ 277,824	$ 302,033	$ 364,874	$ 335,298
Funds flow provided by operations(5)	$ 141,201	$ 151,773	$ 180,952	$ 148,307
Per share – basic(2)(4)	1.43	1.50	1.77	1.43
Per share – diluted(2)(4)	1.43	1.50	1.77	1.43
Net income (loss)	$ (69,051)	$ 65,793	$ 3,845	$ 60,093
Per share – basic(4)	(0.70)	0.65	0.04	0.58
Per share – diluted(4)	(0.70)	0.65	0.04	0.58
Dividends paid	26,658	28,467	28,528	28,531
Per share – Cdn$(4)(6)	0.385	0.385	0.385	0.375
Capital Expenditures(1)	$ 82,110	$ 82,367	$ 97,797	$ 85,421
Long-term inventory expenditures, net of transfers and sales	$ (2,569)	$ (6,318)	$ 9,817	$ 3,843
Total assets (end of period)	$ 2,155,062	$ 2,290,683	$ 2,324,483	$ 2,355,512
Outstanding shares (end of period) (000s)	98,339	100,031	101,616	102,914
Working capital surplus (end of period)(3)(5)	$ 59,397	$ 37,509	$ 34,156	$ 55,901

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(2) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures Advisory".
(3) Working capital does not include the undrawn amount available on the credit facility.
(4) Per share amounts (with the exception of dividends) are based on weighted average common shares. Dividends paid per share are based on the number of common shares outstanding at each dividend record date.
(5) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".
(6) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Factors that Caused Variations Quarter Over Quarter

Trends in net income, oil and natural gas sales and funds flow provided by operations are primarily associated with fluctuations in commodity sales from production which reflect changes in production levels and commodity prices, in addition to fluctuations in foreign currency (see "Foreign Exchange" section). Net income is also impacted by changes in non-cash impairment of property, plant and equipment, exploration and evaluation and long term-inventory assets. Changes in income taxes, as discussed in the section "Income Tax", also impact net income for current and deferred taxes, while funds flow provided by operations is impacted by current income taxes. Working capital trends are primarily associated with fluctuations in funds flow provided by operations, capital and long-term inventory expenditures in accordance with the Company's activities, bank debt borrowing or repayment, timing of settlement of receivables and payables and income taxes and the cost associated with share repurchases and dividend payments.

Refer to "Financial and Operating Results" for detailed discussions on variations during the comparative quarters and to Parex's previously issued annual and interim MD&As for further information regarding changes in prior quarters.

Fourth Quarter Results

Consolidated Statements of Comprehensive Income for the three months ended December 31, 2025 and 2024:

($000s) For the three month period ended December 31,	**2025**	2024
Oil and natural gas sales	**$ 248,713**	$ 277,824
Royalties	**(28,649)**	(41,094)
Net revenue	**220,064**	236,730
Other revenue	**2,827**	2,739
Commodity risk management contracts gain (loss)	**635**	(1,160)
Revenue	**223,526**	238,309
Expenses		
Production	**57,073**	67,708
Transportation	**23,081**	16,877
Purchased oil	**—**	59
General and administrative	**17,657**	17,900
Impairment of property, plant and equipment assets	**—**	78,417
Impairment of exploration and evaluation assets	**11,140**	49,424
Impairment of long-term inventory	**6,470**	10,000
Equity settled share-based compensation expense	**183**	223
Cash settled share-based compensation expense	**9,863**	5,926
Depletion, depreciation and amortization	**54,270**	53,984
Other expenses	**11,785**	2,208
Foreign exchange (gain) loss	**(2,089)**	2,194
Unrealized gain on marketable securities	**(4,616)**	—
	184,817	304,920
Finance (income)	**(1,154)**	(998)
Finance expense	**5,076**	4,318
Net finance expense	**3,922**	3,320
Income (loss) before income taxes	**34,787**	(69,931)
Income tax (recovery)		
Current tax expense (recovery)	**1,235**	(5,629)
Deferred tax (recovery) expense	**(41,313)**	4,749
	(40,078)	(880)
Net income (loss) and comprehensive income (loss) for the period	**$ 74,865**	$ (69,051)

Liquidity and Capital Resources

The Company remains committed to delivering returns to shareholders, while also investing in its assets to provide a total shareholder return. Typically, the Company relies on funds flow provided by operations and its credit facility to meet capital requirements, dividend payments, share repurchases and maintain liquidity. After evaluating its current liquidity, working capital position, projected working capital needs, operational results, and financial forecasts, the Company anticipates that its available cash and cash equivalents, credit facilities, and expected funds flow provided by operations will be sufficient to support the growth of the Company and fund development activities. While the Company deems this outlook reasonable, available cash and cash equivalents are subject to variations and risk associated with ordinary operations, and it cannot guarantee that all or part of its liquidity objective will be met, that sufficient internal funds will be generated, or that external financing will be available if needed.

The Company can adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure, share buy-back and dividend programs to the extent the capital expenditures are not committed. The Company considers its capital structure currently to include shareholders' equity, the credit facility and its working capital. As at December 31, 2025, shareholders' equity was $1,952.9 million (December 31, 2024 - $1,831.3 million).

As at December 31, 2025, the Company had a working capital surplus(1) of $28.0 million as compared to a working capital surplus(1) of $59.4 million at December 31, 2024.

As at December 31, 2025, Parex held $58.3 million of unrestricted cash compared to $98.0 million at December 31, 2024 and $69.8 million at September 30, 2025. The Company's cash balances reside primarily in current accounts with chartered financial institutions, the majority of which are held on account in Canada, Switzerland and Colombia in USD.

Parex's senior secured credit facility is with a syndicate of three Canadian banks has a current borrowing base of $240.0 million (December 31, 2024 - $240.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash or letter of credit needs as they arise. As at December 31, 2025, $33.0 million (December 31, 2024 - $60.0 million) was drawn on the credit facility. The credit facility is secured by the Company's Colombian assets and has final maturity date of May 21, 2027. The next annual review is scheduled to occur in May 2026. The next re-determination of the credit facility is not expected to impact the Company's current or future operations, reduce the 2026 outlook or change the Company's guidance. Parex expects to draw on the credit facility at various times to manage timing differences associated with timing of vendor payments and oil sales collections. Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1, and other standard business operating covenants. The Company is in compliance with all covenants.

Refer to note 29 - Commitments and Contingencies of the audited consolidated financial statements for a description of the performance guarantees as well as the unsecured letters of credit.

(1) Capital Management Measure. See "Non-GAAP and Other Financial Measures Advisory".

Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at December 31, 2025, the Company had 95,974,136 common shares outstanding compared to 98,339,036 at December 31, 2024, a decrease of 2%. At March 3, 2026, the common shares outstanding remains as 95,974,136.

The Company has a stock option plan that provides for the issuance of stock options to acquire common shares to the Company's officers, executives and certain employees resulting in common shares issued from treasury.

As at March 3, 2026, Parex had the following securities outstanding:

	Number	%
Common shares	95,974,136	99
Stock options	1,085,025	1
	97,059,161	100

As of the date of this MD&A, total stock options outstanding represent approximately 1% of the total issued and outstanding common shares.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, Parex has entered into arrangements and incurred obligations that will affect the Company's future operations and liquidity. These commitments primarily relate to joint venture farm-in arrangements, business collaboration agreements and exploration work commitments including seismic and drilling activities. The Company has discretion regarding the timing of capital spending for exploration work commitments, provided that the work is completed by the end of the exploration periods specified in the contracts or the Company can negotiate extensions of the exploration periods. The Company's exploration commitments are described in the Company's AIF under "Principal Properties". These obligations and commitments are considered in assessing cash requirements in the discussion of future liquidity.

In Colombia, the Company has provided guarantees to the ANH and Empresa Colombiana de Petróleos S.A., ("Ecopetrol") joint venture blocks related to the exploration work commitments on its Colombian concessions in the amount of $235.1 million as at December 31, 2025 (December 31, 2024 - $160.7 million). The guarantees have been provided in the form of letters of credit for varying terms that are mainly provided by select Latin American banks on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks.

At December 31, 2025, the total lease obligation was $9.1 million (December 31, 2024 - $5.2 million) of which $7.8 million (December 31, 2024 - $4.6 million) is classified as long-term in accordance with the lease terms.

The following table summarizes the Company’s estimated undiscounted commitments as at December 31, 2025:

($000s)	Total	<1 year	1 – 3 years	4 – 5 years	>5 years
Exploration	$ 753,488	$ 42,434	$ 242,619	$ 468,435	$ —
Office and accommodations[1]	6,966	2,984	2,815	1,167	—
Decommissioning and Environmental Obligations	274,188	10,158	—	—	264,030
Total	**$ 1,034,642**	**$ 55,576**	**$ 245,434**	**$ 469,602**	**$ 264,030**

(1) Includes minimum lease payment obligations associated with leases for office space and accommodations.

Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2023	**$ 71,523**	**$ 24,209**	**$ 95,732**
Additions	5,398	332	5,730
Settlements of obligations during the year	(7,038)	(3,235)	(10,273)
Loss on settlement of obligations	1,593	—	1,593
Accretion expense	6,853	2,353	9,206
Change in estimate - inflation and discount rates	(9,400)	(3,205)	(12,605)
Change in estimate - costs	1,725	(8,342)	(6,617)
Foreign exchange gain	(2,185)	(2,906)	(5,091)
Balance, December 31, 2024	**$ 68,469**	**$ 9,206**	**$ 77,675**
Additions	6,407	3,275	9,682
Property acquisitions - Note 11	702	118	820
Settlements of obligations during the year	(5,877)	(3,635)	(9,512)
Loss (gain) on settlement of obligations	596	(449)	147
Accretion expense	8,160	962	9,122
Change in estimate - inflation and discount rates	(6,197)	(1,192)	(7,389)
Change in estimate - costs	2,216	1,490	3,706
Foreign exchange loss	3,087	1,827	4,914
Balance, December 31, 2025	**77,563**	**11,602**	**89,165**
Current obligation	(7,318)	(2,840)	(10,158)
Long-term obligation	**$ 70,245**	**$ 8,762**	**$ 79,007**

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company’s internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at December 31, 2025, with the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately $244.5 million as at December 31, 2025 (December 31, 2024 - $216.8 million) with the majority of these costs anticipated to occur in 2033 or later. A risk-free discount rate of 12.5% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2024 - 11.2% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used in 2025 and 2024 are based on forecast Colombia rates.

Included in the decommissioning liability is $7.3 million (December 31, 2024 - $11.7 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately $29.7 million as at December 31, 2025 (December 31, 2024 - $24.6 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.5% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2024 - 11.2% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used in 2025 and 2024 are based on forecast Colombia rates.

Included in the environmental liability is $2.8 million (December 31, 2024 - $2.9 million) that is classified as a current obligation.

A change to the assumed discount rate or inflation rate would have an the following impact on the decommissioning and environmental liabilities:

		2025		2024	
As at December 31,	**Sensitivity Range**	**Increase**	**Decrease**	Increase	Decrease
Risk-free discount rate	+/- one percent	**$ (5,551)**	**$ 6,157**	$ (5,349)	$ 6,022
Inflation rate	+/- one percent	**$ 6,600**	**$ (6,013)**	$ 6,406	$ (5,702)

Decommissioning and environmental liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning and environmental expenditures and the impact on the financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. The main factors that can cause expected estimated cash flows in respect of decommissioning and environmental liabilities to change are:

- changes in laws, legislation and regulations;
- construction of new facilities;
- change in commodity price;
- change in the estimate of oil reserves and the resulting amendment to the life of reserves;
- changes in technology; and
- execution of decommissioning and environmental liabilities.

Subsequent Events

NCIB

On January 22, 2026, the Company commenced an NCIB to purchase for cancellation, from time to time, as it considers advisable up to a maximum of 9,407,490 Common Shares on the open market through the facilities of the TSX and/or alternative trading systems. The NCIB will terminate on January 21, 2027.

Proposal

On February 23, 2026, the Company announced that it has submitted an acquisition proposal (the "Proposal") to the Board of Directors of Frontera Energy Corporation (TSX: FEC) ("Frontera") to acquire all of Frontera's Colombian upstream business in an all-cash offer for consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million.

Binding Proposal

On March 2, 2026, the Company submitted a binding acquisition proposal (the "Binding Proposal") to the Board of Frontera Energy Corporation (TSX: FEC) ("Frontera") to acquire all of Frontera's Colombian upstream business in an all-cash offer for consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million. On the same day, Frontera provided an update on the previously-announced non-binding proposal by Parex, acknowledging receipt of a binding offer of $525 million and awaiting confirmation of certain terms.

Advisory on Forward-Looking Statements

Certain information regarding Parex set forth in this MD&A, including assessments by the Company's management of the Company's plans and future operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "plan", "expect", "forecast", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are intended to identify forward-looking statements. Such statements represent the Company's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although the Company's management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex. In particular, forward-looking statements contained in this MD&A include, but are not limited to, statements with respect to:

- the Company's operational strategy, plans, priorities and focus;
- Parex's expectation to provide a competitive return of capital through dividends and share repurchases, while investing in the Company's assets to provide a total shareholder return;
- Parex's expectations as to debt levels, commodity risk management and other hedging activities;
- Parex's 2026 guidance, including its anticipated funds flow provided by operations netback, capital expenditures; funds flow provided by operations, free funds flow and annual average production;
- Parex's expectation that crude oil inventory in future periods will be in line with normal historic levels;
- Parex's anticipated 2026 production expense per boe;
- Parex's expectations that its transportation expense will fluctuate period over period due to the mix of sales contracts types in force during the period;
- that Parex will review its exposure to foreign currency variations on an ongoing basis and maintains cash deposits primarily denominated in USD and COP in Canada, Switzerland and Colombia;
- Parex's foreign exchange sensitivity analysis;
- Parex's expectations regarding legal provisions, including the anticipated outcomes, estimated amounts and timing of potential outflows in connection therewith;
- Parex's approach to risk management and cash flow variability;
- Parex's plans to relinquish certain blocks;
- Parex's intentions to deploy long-lead inventory over the coming years and that Parex secures material and equipment ahead of its upcoming capital programs;
- the terms of the Company's credit facility including the timing of the next annual review and borrowing base redetermination;
- the Company's plan to draw on the credit facility to manage timing differences associated with timing of vendor payments and oil sales collections;
- the Company's expectation that its available cash and cash equivalents, credit facilities, and expected funds flow provided by operations will be sufficient to support the growth of the Company and fund development activities;
- Parex's ability to adjust its capital structure and the mechanics thereof;
- Parex's estimated undiscounted commitments, including exploration, office and accommodations and, decommissioning and environmental obligations, and the anticipated timing thereof;
- the anticipated total undiscounted cash flows required to settle the Company's decommissioning and environmental liability cost, the anticipated timing thereof, and the internal resources available to the Company at the time of settlement;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy and the fluctuation of earnings based on strip prices;
- the Company's estimated effective tax rate for 2026;
- anticipated Brent and WTI prices;
- terms of certain of Parex's contractual obligations;
- Parex's plan to monitor and disclose key metrics surrounding the environmental impacts of its operations;
- Parex's expectations regarding the Binding Proposal including the value and benefits thereof; and
- the statements set forth under "Accounting Policies and Estimates" in this MD&A.

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to: the impact of general economic conditions in Canada and Colombia; determination by Organization of Petroleum Exporting Countries ("OPEC") and other country as to production levels; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced in Canada and Colombia; continued volatility and fluctuations in market prices for oil; the impact of significant declines in market prices for oil; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; partner approval of capital work programs and other matters requiring approval; imprecision in reserve, resource and revenue estimates; incorrect forecasts of the production and growth potential of Parex's assets; obtaining required approvals of regulatory authorities in Canada and Colombia; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; the risk that tariffs, taxes, restrictions or prohibitions on import or export of certain goods including oil and gas may have on the Company, the oil and gas industry or the global economy; ability to access sufficient capital from internal and external sources; risk that the fines and penalties recognized as legal provisions may be more than anticipated or outflows in respect thereof may occur sooner than anticipated; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; the risk that Parex is unable to realize the anticipated benefits of acquisitions and dispositions, including of the GeoPark Shares or the Binding Proposal; the risk that Parex may not consummate a transaction with GeoPark or that Parex may incur a loss on the GeoPark Shares; the risk that Parex may incur significant costs related to the Binding Proposal, regardless of whether the Binding Proposal is successful or that Parex may not be able to complete a transaction with Frontera on the terms or timeline anticipated, or at all; risk of failure to achieve the anticipated benefits associated with acquisitions; failure of counterparties to perform under the terms of their contracts; changes to pipeline capacity; the risk that Parex's evaluation of its existing portfolio of development and exploration opportunities may not be consistent with its expectations; failure to meet expected production targets; the risk that Parex may not have sufficient financial resources in the future to pay a divided or repurchase shares under its NCIB; the risk that the Board may not declare dividends in the future and that there may not be base dividend growth or that Parex's dividend policy changes; the risk that Parex's risk management strategy may not be an effective means of managing and forecasting cash flow; the risk that Parex's capital expenditures, growth in production and production per share may be different than anticipated; the risk that the Company's capital and operating expenditures relating to the protection of the environment may be greater than anticipated; the risk that the Company's financial and operating results including, its 2026 guidance, may not be consistent with its expectations; the risk that the Company's environmental strategies may not be successful and that the Company may not remain in material compliance with environmental protection legislation; the risk that Parex may not deploy its long-lead inventory when anticipated; the risk that Parex may not be successful in attracting and retaining qualified successors to its Chief Executive Officer and other senior officers in the event of departure; the risk that the Company's inventory deployment in 2026 may be more or less than anticipated; the risks discussed under "Decommissioning and Environmental Liabilities" in this MD&A; the risks discussed under "Risk Factors" in the Company's AIF; and other factors, many of which are beyond the control of the Company. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca).

Although the forward-looking statements contained in this MD&A are based upon assumptions which management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this MD&A, Parex has made assumptions regarding, among other things: current and future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; access to areas of the Company's operations and infrastructure in light of the impact of community unrest on the Company's operations; future exchange rates; the price of oil; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies and environmental legislation on the Company's operations; recoverability of reserves and future production rates; timing and number of dry hole write-offs permitted for Colombian tax purposes; the anticipated benefits from the voluntary corporate restructuring; royalty rates; future operating costs; foreign exchange rates; the duration and impact of tariffs, taxes, restrictions or prohibition of importing goods including oil and natural gas; the status of litigation; timing of drilling and completion of wells; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; on-stream timing of production from successful exploration wells; operational performance of non-operated producing fields; pipeline capacity; that Parex will have sufficient financial resources in the future to pay a dividend; that the Board will declare dividends in the future; that Parex will have sufficient financial resources to repurchase shares under its NCIB; that strip prices will remain unchanged; and other matters. The ability of the Company to carry out its business plan is primarily dependent upon the continued support of its shareholders, the discovery of economically recoverable reserves and the ability of the Company to obtain financing or generate sufficient cash flow to develop such reserves.

Forward-looking statements and other information contained in this MD&A concerning the oil and natural gas industry in the countries in which it operates and the Company's general expectations concerning this industry are based on estimates prepared by Management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Management has included forward looking information, and the above summary of assumptions and risks related to forward-looking information in this MD&A in order to provide shareholders with a more complete perspective on the Company’s current and future operations and such information may not be appropriate for other purposes. The Company’s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Parex will derive there from. These forward-looking statements are made as of the date of this MD&A and Parex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

This MD&A contains information that may be considered a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to: Parex's 2026 guidance, including its anticipated funds flow provided by operations netback, capital expenditures, funds flow provided by operations, and free funds flow; Parex's anticipated 2026 production expense per boe; Parex's expectations that its transportation expense will fluctuate period over period due to the mix of sales contracts types in force during the period; Parex's foreign exchange sensitivity analysis; Parex's estimated undiscounted commitments, including exploration, office and accommodations and decommissioning and environmental obligations; and the anticipated timing thereof; the anticipated total undiscounted cash flows required to settle the Company's decommissioning and environmental liability cost, the anticipated timing thereof, and the internal resources available to the Company at the time of settlement; Parex's estimated fines and penalties recognized under legal provisions, including the anticipated timing thereof; and the Company's estimated effective tax rate for 2026; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will vary from the amounts set forth in this MD&A and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such financial outlook. The financial outlook contained in this MD&A was made as of the date of this MD&A and was provided for the purpose of providing further information about the Company's potential future business operations. Readers are cautioned that the financial outlook contained in this MD&A is not conclusive and is subject to change.

Distribution Advisory

The Company's future shareholder distributions, including but not limited to the payment of dividends and the acquisition by the Company of its shares pursuant to its NCIB, if any, and the level thereof is uncertain. Any decision to pay further dividends on the common shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith and any special dividends) or acquire shares of the Company will be subject to the discretion of the Board of Directors of Parex and may depend on a variety of factors, including, without limitation the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Company under applicable corporate law. Further, the actual amount, the declaration date, the record date and the payment date of any dividend are subject to the discretion of the Board. There can be no assurance that the Company will pay dividends or repurchase any shares of the Company in the future.

Oil & Gas Matters Advisory

This MD&A contains a number of oil and gas metrics, including operating netbacks and FFO netbacks. These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide security holders with measures to compare the Company's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment or other purposes.

The term "Boe" means a barrel of oil equivalent on the basis of 6 thousand cubic feet ("Mcf") of natural gas to 1 bbl. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 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. Given 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 Mcf:1Bbl, utilizing a conversion ratio at 6 Mcf:1 Bbl may be misleading as an indication of value.

Non-GAAP and Other Financial Measures Advisory

This MD&A uses various "non-GAAP financial measures", "non-GAAP ratios", "supplementary financial measures" and "capital management measures" (as such terms are defined in NI 52-112), which are described in further detail below. Such measures are not standardized financial measures under IFRS and might not be comparable to similar financial measures disclosed by other issuers. Investors are cautioned that non-GAAP financial measures should not be construed as alternatives to or more meaningful than the most directly comparable GAAP measures as indicators of Parex's performance.

These measures facilitate management's comparisons to the Company's historical operating results in assessing its results and strategic and operational decision-making and may be used by financial analysts and others in the oil and natural gas industry to evaluate the Company's performance. Further, management believes that such financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Company's principal business activities.

Set forth below is a description of the non-GAAP financial measures, non-GAAP ratios, supplementary financial measures and capital management measures used in this MD&A.

Non-GAAP Financial Measures

Capital expenditures, *is a non-GAAP financial measure which the Company uses to describe its capital costs associated with oil and gas expenditures. The measure considers both property, plant and equipment expenditures and exploration and evaluation asset expenditures which are items in the Company's statement of cash flows for the period and is calculated as follows:*

	For the three months ended December 31,		For the year ended December 31,		
($000s)	**2025**	2024	**2025**	2024	2023
Property, plant and equipment expenditures	**$ 47,575**	$ 62,799	**$ 200,595**	$ 221,250	$ 310,933
Exploration and evaluation expenditures	**37,045**	19,311	**109,730**	126,445	172,410
Capital expenditures	**$ 84,620**	$ 82,110	**$ 310,325**	$ 347,695	$ 483,343

	For the three months ended					
($000s)	September 2025	June 2025	March 2025	September 2024	June 2024	March 2024
Property, plant and equipment expenditures	$ 59,002	$ 49,067	$ 44,951	$ 68,406	$ 49,214	$ 40,831
Exploration and evaluation expenditures	20,959	39,623	12,103	13,961	48,583	44,590
Capital expenditures	$ 79,961	$ 88,690	$ 57,054	$ 82,367	$ 97,797	$ 85,421

Free funds flow, *is a non-GAAP financial measure that is determined by funds flow provided by operations less capital expenditures. The Company considers free funds flow to be a key measure as it demonstrates Parex's ability to fund returns of capital, such as the NCIB or dividends, without accessing outside funds and is calculated as follows:*

	For the three months ended December 31,		For the year ended December 31,		
($000s)	**2025**	2024	**2025**	2024	2023
Cash provided by operating activities	**$ 107,744**	$ 67,847	**$ 424,756**	$ 569,915	$ 376,471
Net change in non-cash assets and liabilities	**15,178**	73,354	**30,229**	52,318	291,311
Funds flow provided by operations	**122,922**	141,201	**454,985**	622,233	667,782
Capital expenditures	**84,620**	82,110	**310,325**	347,695	483,343
Free funds flow	**$ 38,302**	$ 59,091	**$ 144,660**	$ 274,538	$ 184,439

EBITDA, *is a non-GAAP financial measure that is defined as net income (loss) adjusted for finance income and expense, other expense, income tax expense (recovery) and depletion, depreciation and amortization.*

Adjusted EBITDA, *is a non-GAAP financial measure defined as EBITDA adjusted for non-cash impairment charges, share-based compensation expense (recovery), unrealized foreign exchange gains (losses) and unrealized gains (losses) on risk management contracts and marketable securities.*

The Company considers EBITDA and Adjusted EBITDA to be key measures as they demonstrate Parex's profitability before finance income and expenses, taxes, depletion, depreciation and amortization and other non-cash items. A reconciliation from net income to EBITDA and Adjusted EBITDA is as follows:

	For the three months ended December 31,		For the year ended December 31,		
($000s)	**2025**	2024	**2025**	2024	2023
Net income (loss)	**$ 74,865**	$ (69,051)	**$ 255,083**	$ 60,680	$ 459,309
Adjustments to reconcile net income (loss) to EBITDA:					
Finance income	**(1,154)**	(998)	**(4,369)**	(4,315)	(14,055)
Finance expense	**5,076**	4,318	**21,402**	18,408	13,834
Other expense	**11,785**	2,208	**29,200**	6,227	2,582
Income tax (recovery) expense	**(40,078)**	(880)	**(20,277)**	248,592	(5,070)
Depletion, depreciation and amortization	**54,270**	53,984	**200,405**	215,770	194,229
EBITDA	**$ 104,764**	$ (10,419)	**$ 481,444**	$ 545,362	$ 650,829
Non-cash impairment charges	**17,610**	137,841	**17,610**	142,502	142,540
Share-based compensation expense	**10,046**	6,149	**30,516**	1,462	30,364
Unrealized foreign exchange (gain) loss	**677**	2,581	**(10,857)**	29,603	(6,453)
Unrealized (gain) loss on risk management contracts	**172**	1,160	**(1,160)**	1,160	—
Unrealized gain on marketable securities	**(4,616)**	—	**(4,616)**	—	—
Adjusted EBITDA	**$ 128,653**	$ 137,312	**$ 512,937**	$ 720,089	$ 817,280

Operating netback, *is a non-GAAP financial measure that the Company considers to be a key measure as it demonstrates Parex's profitability relative to current commodity prices. Parex calculates operating netback as oil and natural gas sales from production less royalties, operating, and transportation expense. Refer to "Financial and Operational Results – Consolidated Results of Operations" for the calculation of operating netback.*

Non-GAAP Ratios

Operating netback per boe, *is a non-GAAP ratio that the Company considers to be a key measure as it demonstrates Parex's profitability relative to current commodity prices. Parex calculates operating netback per boe as operating netback divided by the total equivalent sales volume including purchased oil volumes for oil and natural gas sales price and transportation expense per boe and by the total equivalent sales volume excluding purchased oil volumes for royalties and operating expense per boe.*

Funds flow provided by operations netback per boe*, is a non-GAAP ratio that includes all cash generated from operating activities and is calculated before changes in non-cash assets and liabilities, divided by produced oil and natural gas sales volumes. The Company considers funds flow provided by operations netback per boe to be a key measure as it demonstrates Parex's profitability after all cash costs relative to current commodity prices.*

Basic and diluted funds flow provided by operations per share or FFO per share, *is a non-GAAP ratio that is calculated by dividing funds flow provided by operations by the weighted average number of basic and diluted shares outstanding. Parex presents basic and diluted funds flow provided by operations per share whereby per share amounts are calculated using weighted-average shares outstanding, consistent with the calculation of earnings per share. The Company considers basic and diluted funds flow provided by operations per share or FFO per share to be a key measure as it demonstrates Parex's profitability after all cash costs relative to the weighted average number of basic and diluted shares outstanding.*

Capital Management Measures

Funds flow provided by operations, *is a capital management measure that includes all cash generated from operating activities and is calculated before changes in non-cash assets and liabilities. The Company considers funds flow provided by operations to be a key measure as it demonstrates Parex's profitability after all cash costs. A reconciliation from cash provided by operating activities to funds flow provided by operations is as follows:*

	For the three months ended December 31,		For the year ended December 31,		
($000s)	**2025**	2024	**2025**	2024	2023
Cash provided by operating activities	**$107,744**	$ 67,847	**$ 424,756**	$ 569,915	$ 376,471
Net change in non-cash assets and liabilities	**15,178**	73,354	**30,229**	52,318	291,311
Funds flow provided by operations	**$122,922**	$ 141,201	**$ 454,985**	$ 622,233	$ 667,782

	For the three months ended					
($000s)	September 2025	June 2025	March 2025	September 2024	June 2024	March 2024
Cash provided by operating activities	$ 86,992	$ 142,642	$ 87,378	$ 181,874	$ 222,782	$ 97,412
Net change in non-cash assets and liabilities	18,306	(37,821)	34,566	(30,101)	(41,830)	50,895
Funds flow provided by operations	$ 105,298	$ 104,821	$ 121,944	$ 151,773	$ 180,952	$ 148,307

Working capital surplus (deficit), *is a capital management measure which the Company uses to describe its liquidity position and its ability to meet its short-term liabilities. Working capital surplus (deficit) is defined as current assets less current liabilities:*

	For the three months ended December 31,		For the year ended December 31,		
($000s)	**2025**	2024	**2025**	2024	2023
Current assets	**$273,994**	$245,943	**$ 273,994**	$ 245,943	$ 337,175
Current liabilities	**245,967**	186,546	**245,967**	186,546	258,148
Working capital surplus	**$ 28,027**	$ 59,397	**$ 28,027**	$ 59,397	$ 79,027

	For the three months ended					
($000s)	September 2025	June 2025	March 2025	September 2024	June 2024	March 2024
Current assets	$ 224,109	$ 239,485	$ 259,256	$ 248,208	$ 281,846	$ 276,113
Current liabilities	227,276	219,437	190,216	210,699	247,690	220,212
Working capital surplus (deficit)	$ (3,167)	$ 20,048	$ 69,040	$ 37,509	$ 34,156	$ 55,901

Supplementary Financial Measures

"DD&A expense per boe" is comprised of DD&A expense, as determined in accordance with IFRS, divided by the Company's total production.

"Dividends paid per share" is comprised of dividends declared, as determined in accordance with IFRS, divided by the number of shares outstanding at the dividend record date.

"Effective current tax rate as a per cent of funds flow provided by operations before tax" is comprised of current income tax expense, as determined in accordance with IFRS, divided by funds flow provided by operations before tax.

"G&A expense per boe" is comprised of net G&A expense after recoveries and capitalization, as determined in accordance with IFRS, divided by the Company's total production.

"Net revenue per boe" is comprised of net revenue, as determined in accordance with IFRS, divided by the total equivalent sales volume and includes purchased oil volumes.

"Non-operated production expense per boe" is comprised of operated production expense, as determined in accordance with IFRS, divided by the total equivalent non-operated sales volume and excludes purchased oil volumes.

"Oil and natural gas sales price per boe" is comprised of total commodity sales from oil and natural gas production, as determined in accordance with IFRS, divided by the Company's total oil and natural gas sales volumes including purchased oil volumes.

"Operated production expense per boe" is comprised of operated production expense, as determined in accordance with IFRS, divided by the total equivalent operated sales volume and excludes purchased oil volumes.

"Price differential and transportation expense per bbl" is comprised of realized oil sales price per bbl, as defined herein, less Brent crude price to calculate the price differential, plus transportation expense per bbl as defined herein.

"Production expense per boe" is comprised of production expense, as determined in accordance with IFRS, divided by the total equivalent sales volume and excludes purchased oil volumes.

"Realized oil sales price per bbl" is comprised of total oil sales, as determined in accordance with IFRS, divided by the Company's total oil sales volumes equivalent sales volume including purchased oil volumes.

"Realized natural gas price per Mcf" is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas sales volumes.

"Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the total equivalent sales volume and excludes purchased oil volumes.

"Royalties as a percentage of sales" is comprised of royalties, as determined in accordance with IFRS, divided by the total equivalent sales from production, excluding purchased oil volumes, as determined in accordance with IFRS.

"Transportation expense per bbl" is comprised of transportation expense, as determined in accordance with IFRS, divided by the Company's total oil sales volumes equivalent sales volume including purchased oil volumes.

"Transportation expense per boe" is comprised of transportation expense, as determined in accordance with IFRS, divided by the total equivalent sales volumes including purchased oil volumes.

Environmental Initiatives Impacting Parex

In Colombia there is currently a nascent regulation that obliges companies to specifically monitor and report greenhouse gas ("GHG") emissions. Although at the present time there is no enforceable regulation related to climate change or GHG emissions in Colombia, Parex has a plan in place to monitor and disclose key metrics surrounding the environmental impacts of Parex's operations. Climate change regulation has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Colombia. Such regulations impose certain costs and risks on the industry, and there remains some uncertainty with regard to the impact of climate change and environmental laws and regulations on Parex, as Parex is unable to predict additional legislation or amendments that the Colombian government may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

As of December 31, 2022, Colombia has ratified the Regional Agreement on Access to Information, Public Participation and Justice in Environmental Matters in Latin America and the Caribbean (the "Escazu Agreement"). The Company cannot predict with any certainty at this time the impacts to the Company that implementation of the Escazu Agreement may entail, as no details are yet available regarding the ways in which implementation will be carried out for the countries that have ratified it. However, it is anticipated that the Escazu Agreement will increase the participation of communities and the demand for access to information, which could affect the processes for obtaining environmental licenses, permits and authorizations applicable to the Company, may result in the incurrence of additional unanticipated costs, and could create friction with the communities, among other risks.

Business Environment and Risks

Parex is exposed to a number of risks through the pursuit of its strategic objectives including but not limited to operational, financial, competitive, political and environmental risks. Some of these risks impact the oil and gas industry as a whole and others are unique to the Company's operations. As a participant in the oil and natural gas industry, Parex is exposed to risks such as unsuccessful exploration and exploitation activities, the inability to find new reserves that are commercially and economically feasible, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, stock market volatility, debt service which may limit timing or amount of dividends as well as market price of shares, financial and liquidity risks and environmental and safety risks.

Parex's indirect Colombian entities have various working interests in numerous exploration and production blocks in the Llanos basin, as well as the Upper Magdalena, Middle Magdalena and Lower Magdalena basins. Further, all of Parex's oil and gas reserves and production are in Colombia. A number of the Company's contracts authorizing the exploration, development and production of hydrocarbons have exploration commitments, and in some cases, a portion of the commitments is guaranteed by issued letters of credit. Therefore, Parex will be subject to additional risks associated with international operations in Colombia.

The Company works to mitigate these risks by hiring or contracting highly skilled professionals who have demonstrated the ability to generate high quality proprietary geological and geophysical prospects. Parex has retained independent petroleum consultants that assist the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, production forecasts and future development costs. Such estimates will vary from actual results and such variations may be material.

The Company mitigates its risk related to producing hydrocarbons through the utilization of current technology and information systems. In addition, Parex operates the majority of its properties and, therefore, has significant control over the timing, direction and costs related to exploration commitments and development opportunities. When the Company does not operate, it relies on its joint venture partners to maintain operational control.

Parex is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in foreign currency exchange rates which, in turn, respond to economic and political circumstances throughout the world. Oil and natural gas prices are affected by worldwide supply and demand fundamentals. Parex uses derivative contracts to mitigate its exposure to the potential adverse impacts of commodity price and foreign exchange volatility.

Exploration and production for oil and gas is capital intensive. In addition to funds flow, Parex utilizes bank financing to support ongoing capital investments which exposes the Company to fluctuations in interest rates on its bank debt. Funds flow also fluctuates with changing commodity prices. Equity and debt capital are subject to market conditions, and availability and cost may increase or decrease from time to time.

The impact of any risk or a combination of risks may adversely affect, among other things, Parex's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict its ability to pursue its strategic priorities, respond to changes in the operating environment, and fulfill commitments and obligations, and may materially affect the market price of the Company's securities.

Additional information regarding risk factors, assumptions and uncertainties can be found under the heading "Forward Looking Statements" of this MD&A and in the "Risk Factors" section in the AIF of the Company, which is available on the Company's SEDAR+ profile at www.sedarplus.ca.

Internal Controls over Financial Reporting

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation authorities is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Parex evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded Parex DC&P were effective as at December 31, 2025.

Internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109, includes those policies and procedures that:

1) Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Parex;
2) Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Parex are being made in accordance with authorizations of management and Directors of Parex; and
3) Are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company’s assets that could have a material effect on the annual financial statements or interim financial reports.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Parex. They have, as at the financial year ended December 31, 2025, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Parex officers used to design the Company’s ICFR is the 2013 Internal Control - Integrated Framework (“COSO Framework”) published by The Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Parex conducted an evaluation of the effectiveness of the Company’s ICFR as at December 31, 2025 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2025, Parex maintained effective ICFR. It should be noted that while Parex officers believe that the Company’s controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in Parex’s ICFR during the year ended December 31, 2025 that materially affected, or are reasonably likely to materially affect, the Company’s ICFR.

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the twelve months ended December 31, 2025 other than normal course guarantees entered into in the form of letters of credit to support the exploration work commitments on its blocks. For further information refer to "Contractual Obligations, Commitments and Guarantees" section above and note 29 - Commitments and Contingencies in the audited consolidated financial statements.

Financial Instruments and Other Instruments

The Company’s non-derivative financial instruments recognized in the consolidated balance sheet consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity.

Related Party Transactions

Compensation of Key Management Personnel

Key management personnel compensation, including directors, is as follows:

	2025	2024
Salaries, directors' fees and other benefits	**$ 4,306**	$ 4,356
Equity settled share-based compensation	**439**	478
Cash settled share-based compensation	**4,568**	5,846
	$ 9,313	$ 10,680

Other Related Party Transactions

The Company did not have any related party transactions with entities outside the consolidated group for the years ended December 31, 2025 and 2024.

Material Accounting Policies

Refer to note 3 - Summary of Material Accounting Policies of the audited consolidated financial statements for a summary of significant accounting policies applied by the Company.

Significant Accounting Estimates

The preparation of consolidated financial statements in accordance with IFRS requires management to make significant judgments, assumptions and estimates that affect the financial results of the Company. The following discussion outlines the accounting policies and practices involving the use of estimates that the Company believes are critical in determining Parex's financial results.

Oil and natural gas reserves

The Company retains qualified independent reserves evaluators to evaluate the Company's proved and probable oil and natural gas reserves. As at December 31, 2025, and in prior periods, Parex's reserves were evaluated by GLJ Ltd., who are a firm of qualified independent reserves evaluators. The evaluation was conducted in accordance with the COGE handbook and NI 51-101. The Operations and Reserves Committee of the Company's Board of Directors is comprised of independent directors whose mandate is to steward the reserves evaluation process.

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, expected rates of production and the timing of future capital expenditures, all of which are subject to major uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net income, as they are a key component in the calculation of DD&A and for determining potential asset impairment. A downward revision in reserves estimates or an increase in estimated future development costs could result in the recognition of a higher DD&A charge to net income.

Oil and natural gas assets (development and producing costs) are aggregated into CGUs based on their ability to generate largely independent cash flows. If the carrying value of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income. The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Fair value less costs to sell may be determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of impairments charged to net income.

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net income.

Decommissioning and Environmental Liabilities

The Company is required to recognize a liability for future dismantling, decommissioning, environmental, abandoning and site disturbance remediation costs associated with the Company's oil and natural gas properties in accordance with existing laws, contracts or other policies. The fair value of the estimated decommissioning and environmental liability is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related long-lived asset, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to net income, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

Decommissioning and environmental liabilities are determined by using management's best estimate of costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances, industry practices and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total decommissioning and environmental liability. These individual assumptions can be subject to change based on experience. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. The Company estimates future decommissioning and environmental costs based on current estimates adjusted for inflation. This estimate for inflation is also subject to management uncertainty.

Current and Deferred Tax

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities and are measured using substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in income tax rates on deferred tax liabilities and assets is recognized in net income in the period that the change occurs. Deferred tax assets are only recognized to the extent that it is probable that sufficient future taxable income will be available in the applicable jurisdiction to allow the deferred tax assets to be realized.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations from multiple jurisdictions. Rates are also affected by legislative changes. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded in the financial statements. Estimates of current income tax for interim periods are also subject to additional uncertainty. A variety of factors cannot be known until year-end and, therefore, estimates are used for interim period current tax provisions.

Share-Based Compensation

The Company records share-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date and expensed equally over the vesting term of the option. The Company records the cumulative stock option based compensation as contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised option. Any consideration received on the exercise of stock options is credited to share capital. The determination of share-based compensation expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the options. These assumptions, by their nature, are subject to measurement uncertainty.

The fair value of CosRSUs, CosPSUs, LDRSUs and LDPSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares on the date of issuance, and expensed over the vesting period of the CosRSUs, CosPSUs, LDRSUs and LDPSUs. In accordance with the fair value method, increases or decreases in the fair value of the CosRSUs, CosPSUs, LDRSUs and LDPSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

CosPSUs and LDPSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to CosPSUs and LDPSUs eligible to vest at the end of the performance period. The expense recognized over the vesting period of the CosPSUs and LDPSUs is the fair value of the CosPSUs and LDPSUs with an estimated adjustment factor.

The fair value of CRSUs is calculated using the Black-Scholes pricing model based on the market price of the Company's common shares on the date of issuance and expensed over the vesting period of the CRSUs. In accordance with the fair value method, increases or decreases in the fair value of the CRSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

The fair value of a DSU is calculated using the Black-Scholes pricing model based on the five-day weighted average share price at which the common shares of the Company traded for immediately preceding the date of issuance and expensed immediately. In accordance with the fair value method, increases or decreases in the fair value of the DSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired and is assessed for impairment at December 31 of each year. To test for impairment, goodwill is allocated to each of the Company's CGUs, or groups of CGUs, that are expected to benefit from the acquisition and is tested as described in the Company's impairment policy. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal ("FVLCD").

Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU. FVLCD is based on available market information, where applicable. In the absence of such information, FVLCD is determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of a goodwill impairment charge to net earnings.

These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Derivative liabilities

Risk management contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date. The fair value of the risk management contract on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair value is based on quoted market price where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions.

Legal, Environmental Remediation and other Contingent Matters

In respect of these matters, the Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and if such a loss can reasonably be estimated. When any such loss is determined, it is charged to net income. Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to net income when warranted by circumstances.

DIRECTORS

Wayne Foo
Chairman of the Board

Glenn McNamara
Vice Chair

Lynn Azar

Alberto Consuegra

Sigmund Cornelius

Mona Jasinski

Jeff Lawson

G.R. (Bob) MacDougall

Imad Mohsen

Carmen Sylvain

OFFICERS & SENIOR EXECUTIVES

Imad Mohsen
President & Chief Executive Officer

Daniel Ferreiro
President & Country Manager, Parex Resources (Colombia) AG Sucursal

Cameron Grainger
Chief Financial Officer

Eric Furlan
Chief Operating Officer

Mike Kruchten
Sr. Vice President, Capital Markets & Corporate Planning

Joshua Share
Sr. Vice President, Corporate Services

Katie Bernard
Vice President, New Ventures

CORPORATE HEADQUARTERS

Parex Resources Inc.
2700, Eighth Avenue Place, West Tower
585 8 Avenue S.W.,
Calgary, Alberta, Canada T2P 1G1

Tel: 403-265-4800
Fax: 403-265-8216

OPERATING OFFICES

Parex Resources (Colombia) AG Sucursal
Calle 113 No. 7-21, Of. 611,
Edificio Teleport, Torre A
Bogotá, Colombia

Tel: +57 (601) 841-8457

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

Odyssey Trust Company
Calgary, Alberta

RESERVES EVALUATORS

GLJ Ltd.
Calgary, Alberta

INVESTOR RELATIONS

Michael Kruchten
Sr. Vice President, Capital Markets & Corporate Planning

Tel: 403-517-1733

Steven Eirich
Sr. Investor Relations & Communications Advisor

Tel: 587-293-3286

E-mail: investor.relations@parexresources.com

Website: www.parexresources.com

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl(s)	barrel(s)
mbbls	thousand barrels
bbl(s)/d	barrels of oil per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
boe/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice
kms	Kilometers
FFO	Funds flow provided by operations

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 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.