CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets (unaudited)

As at (thousands of United States dollars)	NOTE	September 30, 2026	December 31, 2025
ASSETS			
Current assets			
Cash and cash equivalents	23	**$ 142,725**	$ 58,328
Restricted cash and cash equivalents	23	**6,418**	5,424
Accounts receivable	5	**228,893**	78,329
Prepaids and other current assets		**20,355**	13,357
Marketable securities	6	**63,590**	45,090
Derivative financial instruments	25	**4,441**	776
Current income tax receivable		**160,424**	68,363
Short-term inventory	7	**62,830**	4,327
		689,676	273,994
Exploration and evaluation	10	**302,539**	161,125
Property, plant and equipment	11	**2,694,049**	1,500,213
Long-term inventory	12	**166,075**	175,426
Other long-term assets	23	**55,513**	14,629
Deferred tax asset		**472,708**	142,253
Goodwill		**73,452**	73,452
		$ 4,454,012	$ 2,341,092
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		**$ 616,785**	235,809
Current portion of customer prepayments	13	**75,553**	—
Current portion of deferred consideration	8	**14,344**	—
Current portion of decommissioning and environmental liabilities	16	**18,970**	10,158
		725,652	245,967
Debt	14	**875,388**	33,000
Lease obligations	15	**16,792**	7,814
Decommissioning and environmental liabilities	16	**340,226**	79,007
Cash settled share-based compensation liabilities	17	**17,676**	15,228
Other long-term liabilities		**31,479**	7,143
Deferred consideration	8	**40,828**	—
Deferred tax liability		**5,439**	—
		2,053,480	388,159
Shareholders' equity			
Share capital	18	**624,984**	621,062
Contributed surplus		**20,665**	20,738
Other reserves		**(198)**	—
Retained earnings		**1,755,081**	1,311,133
		2,400,532	1,952,933
		$ 4,454,012	$ 2,341,092

Commitments and Contingencies (note 27)
See accompanying Notes to the Condensed Interim Consolidated Financial Statements

Approved by the Board:

"signed"	"signed"
Sigmund Cornelius	Bob MacDougall
Director	Director

Consolidated Statements of Net Income and Comprehensive Income (unaudited)

(thousands of United States dollars, except per share amounts)	NOTE	For the three months ended September 30, 2026	2025	For the nine months ended September 30, 2026	2025
Oil and natural gas sales	19	**$ 633,549**	$ 252,424	**$1,370,942**	$ 757,129
Royalties		**(86,452)**	(30,785)	**(196,201)**	(98,103)
Net revenue		**547,097**	221,639	**1,174,741**	659,026
Other revenue	19	**1,971**	2,168	**6,635**	6,999
Commodity risk management contracts loss	25	**—**	(3,021)	**(31,665)**	(2,054)
Revenue		**549,068**	220,786	**1,149,711**	663,971
Expenses					
Production		**165,039**	62,120	**313,121**	168,470
Transportation		**53,667**	19,124	**107,943**	53,363
Purchased crude oil		**50,712**	—	**87,468**	162
General and administrative		**35,790**	19,214	**81,629**	53,669
Unrealized gain on marketable securities	6	**(8,215)**	—	**(18,500)**	—
Transaction costs	8	**—**	—	**29,000**	—
Loss (gain) on acquisition	8	**4,873**	—	**(297,610)**	—
Depletion, depreciation and amortization	11	**100,551**	47,767	**214,222**	146,135
Cash settled share-based compensation expense	17	**15,322**	11,733	**33,209**	19,939
Equity settled share-based compensation expense	18	**273**	169	**712**	531
Other expense	20	**1,777**	3,815	**28,104**	17,415
Foreign exchange gain		**(10,981)**	(5,222)	**(13,230)**	(8,843)
		408,808	158,720	**566,068**	450,841
Finance income	21	**(1,781)**	(1,306)	**(7,925)**	(3,215)
Finance expense	21	**36,281**	5,796	**60,265**	16,326
Net finance expense		**34,500**	4,490	**52,340**	13,111
Income before income taxes		**105,760**	57,576	**531,303**	200,019
Income tax (recovery) expense					
Current tax expense		**16,607**	11,135	**34,567**	32,267
Deferred tax (recovery) expense		**13,898**	(4,035)	**(27,404)**	(12,466)
		30,505	7,100	**7,163**	19,801
Net income for the period		**$ 75,255**	$ 50,476	**$ 524,140**	$ 180,218
Other comprehensive loss					
Foreign currency translation		**(198)**	—	**(198)**	—
Total net income and comprehensive income for the period		**$ 75,057**	$ 50,476	**$ 523,942**	$ 180,218
Basic net income per common share	22	**$ 0.78**	$ 0.52	**$ 5.45**	$ 1.85
Diluted net income per common share	22	**$ 0.78**	$ 0.52	**$ 5.44**	$ 1.85

See accompanying Notes to the Condensed Interim Consolidated Financial Statements

Consolidated Statements of Changes in Equity (unaudited)

For the nine months ended September 30, (thousands of United States dollars)		**2026**		2025
Share capital				
Balance, beginning of period	**$**	**621,062**	$	632,899
Issuance of common shares under equity-settled plans		**3,922**		—
Repurchase of shares		**—**		(8,891)
Balance, end of period	**$**	**624,984**	$	624,008
Contributed surplus				
Balance, beginning of period	**$**	**20,738**	$	20,024
Share-based compensation		**712**		531
Options exercised		**(785)**		—
Balance, end of period	**$**	**20,665**	$	20,555
Other reserves				
Balance, beginning of period	**$**	**—**	$	—
Other comprehensive loss		**(198)**		—
Balance, end of period	**$**	**(198)**	$	—
Retained earnings				
Balance, beginning of period	**$**	**1,311,133**	$	1,178,398
Net income for the period		**524,140**		180,218
Dividends		**(80,192)**		(80,818)
Repurchase of shares		**—**		(9,979)
Balance, end of period	**$**	**1,755,081**	$	1,267,819
	$	**2,400,532**	$	1,912,382

See accompanying Notes to the Condensed Interim Consolidated Financial Statements

Consolidated Statements of Cash Flows (unaudited)

(thousands of United States dollars)	NOTE	For the three months ended September 30, 2026	2025	For the nine months ended September 30, 2026	2025
Operating activities					
Net income		**$ 75,255**	$ 50,476	**$ 524,140**	$ 180,218
Add (deduct) non-cash items					
Unrealized gain on marketable securities	**6**	**(8,215)**	—	**(18,500)**	—
Loss (gain) on acquisition	**8**	**4,873**	—	**(297,610)**	—
Non-cash inventory fair value adjustment	**8**	**–**	—	**9,365**	—
Depletion, depreciation and amortization	**11**	**100,551**	47,767	**214,222**	146,135
Cash settled share-based compensation expense	**17**	**15,322**	11,733	**33,209**	19,939
Equity settled share-based compensation expense	**18**	**273**	169	**712**	531
Non-cash other expense (income)	**20**	**(1,397)**	40	**3,857**	620
Non-cash finance expense	**21**	**12,598**	3,566	**19,480**	9,952
Deferred tax (recovery) expense		**13,898**	(4,035)	**(27,404)**	(12,466)
Unrealized foreign exchange gain		**(16,817)**	(4,246)	**(18,093)**	(11,534)
Unrealized gain on commodity risk management contracts	**25**	**—**	(172)	**(1,281)**	(1,332)
Net change in assets and liabilities	**23**	**(58,113)**	(18,306)	**(80,548)**	(15,051)
Cash provided by operating activities		**138,228**	86,992	**361,549**	317,012
Investing activities					
Exploration and evaluation expenditures	**10**	**(40,091)**	(20,959)	**(147,414)**	(72,685)
Property, plant and equipment expenditures	**11**	**(121,679)**	(59,002)	**(239,092)**	(153,020)
Long-term inventory expenditures, net of transfers and sales	**12**	**1,291**	1,585	**9,351**	9,900
Business acquisition, net of cash acquired	**8**	**—**	—	**(307,179)**	—
Property acquisition	**9**	**—**	—	**—**	(15,968)
Net change in non-cash working capital	**23**	**(53,449)**	3,959	**(38,904)**	35,203
Cash (used in) investing activities		**(213,928)**	(74,417)	**(723,238)**	(196,570)
Financing activities					
Issuance of unsecured notes, proceeds	**14**	**—**	—	**500,000**	—
Issuance costs of unsecured notes	**14**	**—**	—	**(15,380)**	—
Bank debt draw (repayment)	**14**	**82,499**	(8,000)	**49,499**	(50,000)
Payments on lease obligations	**15**	**(2,434)**	(175)	**(4,748)**	(393)
Dividends	**18**	**(26,772)**	(26,892)	**(80,192)**	(80,818)
Issuance of common shares under equity-settled plans	**18**	**250**	—	**3,137**	—
Common shares repurchased	**18**	**—**	(7,606)	**—**	(18,870)
Net change in non-cash working capital	**23**	**—**	146	**—**	(1,082)
Cash provided by (used in) financing activities		**53,543**	(42,527)	**452,316**	(151,163)
Increase (decrease) in cash and cash equivalents and restricted cash and cash equivalents for the period		**(22,157)**	(29,952)	**90,627**	(30,721)
Impact of foreign exchange on foreign currency-denominated cash balances		**1,568**	1,227	**7,093**	3,709
Cash and cash equivalents and restricted cash and cash equivalents, beginning of period	**23**	**182,252**	103,500	**63,943**	101,787
Cash and cash equivalents and restricted cash and cash equivalents, end of period	**23**	**$ 161,663**	$ 74,775	**$ 161,663**	$ 74,775

Supplemental Disclosure of Cash Flow Information (note 23)

See accompanying Notes to the Condensed Interim 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 condensed interim consolidated financial statements were approved by the Board of Directors on November 5, 2026.

2. Basis of Presentation and Material Accounting Policies

a) Statement of compliance

The condensed interim consolidated financial statements for the three and nine months ended September 30, 2026 have been prepared in accordance with IAS 34, 'Interim financial reporting'. The condensed interim consolidated financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2025, which have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards").

The policies applied in these condensed interim consolidated financial statements are based on IFRS Accounting Standards issued and outstanding as of November 5, 2026, the date the Board of Directors approved the condensed interim consolidated financial statements.

b) Basis of measurement

The condensed interim consolidated financial statements have been prepared under the historical cost convention, except for those items which are measured at fair value as discussed in note 4 - Determination of Fair Values.

c) Use of management estimates, judgments and measurement uncertainty

The timely preparation of the condensed interim 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 condensed interim 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 condensed interim consolidated financial statements. Accordingly, actual results could differ from estimated amounts as future confirming events occur.

In preparing these condensed interim consolidated financial statements, the significant judgements made by management in applying the group's accounting policies and the key sources of estimation uncertainty were the same as those applied to the consolidated financial statements for the year ended December 31, 2025.

3. Summary of Material Accounting Policies

The accounting policies adopted are consistent with those of the previous financial year as described in note 3 of the Company's consolidated financial statements for the year ended December 31, 2025 with the addition of the below Amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures.*

On January 1, 2026, the Company adopted the amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* in the interim period ending March 31, 2026. The amendments for disclosures relate to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. There was not a material effect to the Company's condensed interim consolidated financial statements. The Company has applied the election to deem financial liabilities settled in cash using an electronic payment system to be discharged before the settlement date. The amendments have been applied retrospectively with no restatement of comparative information, in accordance with transition requirements on initial application of IFRS 9. There is no adjustment to the opening balance of cash and cash equivalents in the consolidated statements of cash flows.

In addition, due to the acquisition of Sabana Petroleum International Holdings B.V. (formerly Frontera Petroleum International Holdings B.V.) (see Note 8 - Business Combinations), the following additional accounting policies have been updated:

Subsidiaries:
Sabana Resources Corp. (formerly Frontera Energy Colombia Corp.) has been identified as an additional principal operating subsidiary incorporated in Switzerland and its principal business activity is oil and natural gas exploration and development in Colombia. Parex has 100% ownership of this subsidiary.

Customer prepayments:
The Company recognizes each contract in the statement of financial position as either a contract asset or a contract liability, based on the relationship between the Company's performance under the contract and the consideration received from the customer. Additionally, when a customer pays consideration, or when the Company has an unconditional right to consideration (i.e., a receivable) before transferring goods or services, the entity shall present the amount as a contract liability or customer prepayment in the statement of financial position (see Note 13 - Customer Prepayments). This classification applies at the earlier of the payment date or the date the payment becomes due. Financing components embedded in customer prepayment arrangements are recognized using the effective interest method over the term of the agreement when significant financing components exist.

Other comprehensive income:
Other comprehensive income ("OCI") consists of items of income and expense that are recognized outside net income in accordance with IFRS Accounting Standards. OCI includes foreign currency translation differences arising from the translation of foreign operations, which may be reclassified to net income upon disposal of the relevant foreign operation. The income tax effects of items recognized in OCI are recognized in OCI, where applicable.

In addition, due to the closing of the Ecopetrol Strategic Partnership (see Note 8 - Business Combinations), the following accounting policy has been updated:

Deferred Consideration:
Deferred consideration is the Company's obligation to fund future capital expenditures under an acquisition arrangement, to the extent those expenditures relate to the participating interest acquired. At the acquisition date, it is recognized at fair value, measured as the present value of the expected future payments. After initial recognition, it is measured at amortized cost using the effective interest method, with accretion recognized in finance expense. The liability is reduced as the related expenditures are incurred. Changes in the estimated amount or timing of those expenditures are recognized in net income. Expenditures that earn the Company an additional participating interest are not part of the deferred consideration. They are capitalized to property, plant and equipment when incurred.

In addition, due to the recognition of Equity tax in the current period, the following additional accounting policy has been updated:

Equity tax:
Equity tax represents a tax imposed by the Colombian Government on entities whose net equity exceeds a prescribed threshold as of a specified measurement date. The tax is recognized as an expense when the obligating event occurs and the amount can be reliably estimated. The related liability is measured based on the applicable tax rate applied to taxable net equity, considering enacted or substantively enacted tax legislation at the reporting date. Equity tax is recognized in profit or loss and is not included in income tax expense unless required by applicable tax legislation (see Note 20 - Other Expense).

Standards Issued but not yet Effective

i) 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

The methods used in the determination of fair value, for financial and non-financial assets and liabilities have not changed from the previous financial year. Refer to note 4 of the December 31, 2025 consolidated financial statements for details concerning determination of fair values.

5. Accounts Receivable

		September 30, 2026		December 31, 2025
Trade receivables	**$**	**158,142**	$	72,317
Receivables from partners		**37,231**		—
Value added taxes (VAT)		**33,520**		6,012
	$	**228,893**	$	78,329

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. Receivables from partners primarily relate to amounts recoverable from joint venture partners for their share of costs incurred under joint operations. VAT receivable consists of value-added taxes paid on Colombian oil and gas operating, capital, and administrative expenditures that are recoverable from the Colombian tax authorities. All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Marketable Securities

		September 30, 2026		December 31, 2025
Marketable securities	**$**	**63,590**	$	45,090

In 2025, the Company acquired 6,084,986 common shares of GeoPark Ltd (NYSE: GPRK) for aggregate consideration of $40.5 million ($6.65 per share). The fair value of these shares at September 30, 2026 was $63.6 million, resulting in an unrealized gain of $18.5 million, which is recorded in the consolidated statements of net income and comprehensive income.

7. Short-term Inventory

		September 30, 2026		December 31, 2025
Crude oil inventory	**$**	**51,176**	$	4,327
Materials inventory		**11,654**		—
Total	**$**	**62,830**	$	4,327

Crude oil inventory consists of produced and purchased crude oil injected into pipelines and stored in tanks at the balance sheet date. It is measured at the lower of cost and net realizable value, with cost determined using the weighted average cost method. Cost includes the cost of purchased crude oil and the direct and indirect expenditures incurred in bringing the crude oil to its existing location and condition, including production costs, certain transportation costs, depletion expense and royalty expense. At September 30, 2026, the Company had 805.6 mbbls of crude oil inventory (116.9 mbbls at December 31, 2025) and was recorded at $63.53/bbl at September 30, 2026 ($37.05/bbl at December 31, 2025).

Materials inventory consists of materials used in operations and is recorded at the lower of cost and net realizable value.

8. Business Combinations

Frontera Transaction

On June 1, 2026, the Company closed its previously announced acquisition of all the Colombian exploration and production assets of Frontera Energy Corporation ("Frontera"), pursuant to which the Company, through a wholly-owned subsidiary, acquired 100% of the issued and outstanding shares of Sabana Petroleum International Holdings B.V (formerly Frontera Petroleum International Holdings B.V.) ("Sabana"), which holds all of Frontera's exploration and production assets in Colombia, for cash consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million (the "Frontera Transaction"). The Frontera Transaction was funded with the proceeds from the Company's issuance of senior unsecured notes, see Note 14 - Debt for details.

The contingent consideration is payable to Frontera if, within 12 months following the closing of the Frontera Transaction, the Company obtains a contractual amendment or other binding agreement extending the term of the Quifa Association Contract. At the acquisition date, the contingent consideration was recognized at its estimated fair value of $12.5 million, reflecting management's probability-weighted assessment of the payment condition being satisfied. As any payment, if triggered, is expected within 12 months of the acquisition date, the effect of discounting was not material.

The fair value measurement of the contingent consideration is classified within Level 3 of the fair value hierarchy because it uses significant unobservable inputs, principally the probability of obtaining the required contractual extension. The contingent consideration was remeasured at September 30, 2026, with no change in its fair value recognized during the period.

IFRS 3 requires the amounts to record for the underlying assets and liabilities acquired to be determined at the closing date (the "acquisition date") whereas the consideration for the business was negotiated earlier and voted on by the Frontera shareholders on April 30, 2026. Furthermore, deferred tax assets are recorded at undiscounted amounts based on temporary differences existing at the acquisition date and are therefore not recorded at fair value under IFRS. The tax basis of the underlying assets acquired is in Colombian pesos which differs from the functional currency of the Company and due to volatility in currencies this also significantly increased the US dollar equivalent value of the tax pools at the acquisition date relative to the time when the purchase was negotiated. As a result, the Company has estimated that the deferred tax assets contributed to the recognition of a bargain purchase gain approximating the deferred tax assets recognized.

The consolidated statements of net income and comprehensive income include results of operations of the Frontera Transaction since the closing date of June 1, 2026. The Company incurred transaction costs in connection with the Frontera Transaction of $29.0 million for the nine months ended September 30, 2026, which are expensed as incurred and presented in the consolidated statements of net income and comprehensive income.

The below amounts are estimates which were made by management at the time of the preparation of these condensed interim consolidated financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized for a period of up to one year. The pro forma information disclosed below is presented for informational purposes only and is not necessarily indicative of the results that would have been achieved had the Frontera Transaction occurred on January 1, 2026, nor is it indicative of future results.

The key assumptions used in the business combination to calculate the purchase price allocation include reserve estimates of proved plus probable reserves acquired that are based on production forecasts, future commodity prices, future development costs and future production costs.

During the three months ended September 30, 2026, the Company continued to refine the provisional purchase price allocation for the Frontera Transaction as additional information became available regarding facts and circumstances that existed as of the acquisition date. As a result, the Company recognized an additional provision of $11.0 million as at June 1, 2026, with a corresponding increase to property, plant and equipment and decrease of $4.9 million to the deferred tax asset and corresponding bargain purchase gain. The adjustment reflects information obtained during the measurement period relating to conditions that existed at the acquisition date and has therefore been reflected retrospectively in the provisional acquisition accounting.

As a result of the acquisition, the Company recognized a bargain purchase gain of $297.6 million, representing the excess of the fair value of the identifiable net assets acquired over the consideration transferred. The bargain purchase gain was recognized in the consolidated statements of net income and comprehensive income.

Before recognizing the bargain purchase gain, the Company assessed the completeness and accuracy of the assets acquired, liabilities assumed and consideration transferred, including the valuation methodologies and key assumptions applied in determining acquisition-date fair values, in accordance with IFRS 3.

The following table summarizes the recognizable assets acquired, liabilities assumed and consideration paid pursuant to the Frontera Transaction:

Assets acquired and liabilities assumed		
Assets		
Cash and cash equivalents	$	165,859
Restricted cash and cash equivalents		10,657
Accounts receivables		84,094
Prepaids and other current assets		11,181
Short-term inventory		67,569
Current income tax receivable		61,927
Exploration and evaluation assets		11,089
Property, plant and equipment		997,507
Right-of-use-asset		16,003
Other long-term assets		18,198
Deferred tax asset		297,610
Liabilities		
Accounts payable and accrued liabilities		(354,981)
Derivative financial instruments		(1,282)
Long-term debt - unsecured notes		(307,311)
Customer prepayments		(80,300)
Lease obligations		(16,003)
Decommissioning and environmental liabilities		(179,999)
Other long-term liabilities		(8,013)
Net assets acquired	**$**	**793,805**
Consideration transferred		(496,195)
Bargain purchase gain	**$**	**297,610**

Consideration for the acquisition		
Base purchase price	$	500,000
Purchase price adjustments		(16,305)
Cash consideration paid at closing		483,695
Fair value of contingent consideration		12,500
Total consideration	**$**	**496,195**
Cash paid	$	483,695
Less: Cash and cash equivalents acquired		(176,516)
Net cash outflow on acquisition	**$**	**307,179**

The pro forma results for the nine month period ended September 30, 2026 are shown below, as if the Frontera Transaction had occurred on January 1, 2026. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	$	1,839,106
Net revenue less direct costs	$	847,210

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 net income and comprehensive income for the nine months ended September 30, 2026 includes $437.9 million of oil and natural gas sales attributable to the assets acquired since the Frontera Transaction. Revenue less direct costs for the nine months ended September 30, 2026 attributable to the assets acquired since the Frontera Transaction is $138.6 million.

Ecopetrol Strategic Partnership

On July 29, 2026, the Company closed the previously announced executed agreement with its strategic partner Ecopetrol S.A. ("Ecopetrol"), following receipt of the required regulatory approvals. Under the agreement, the Company will earn a 50% participating share in the Casabe and Llanito blocks in the Magdalena Basin of Colombia, upon spudding the first well on each block in exchange for a commitment of a gross capital expenditure program of $250 million over five years, of which $125 million represents the commitment to fund Ecopetrol's share.

The transaction was accounted for as a business combination under IFRS 3 as the initial participating interest acquired by the Company included interests in existing proved developed producing reserves and current production, together with the related operating activities and obligations, which collectively constituted a business. The acquisition-date consideration was determined based on the present value of the Company's future investment commitment attributable to the participating interest acquired at the acquisition date.

The initial acquisition reflects the minimum participating interest in the existing producing properties to which the Company is entitled under the arrangement. The Company's remaining incremental participating interest will be earned through future investment activities under the agreement and is not included in the initial purchase price allocation.

The below amounts are estimates which were made by management at the time of the preparation of these condensed interim consolidated financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized for a period of up to one year.

The key assumptions used in the business combination to calculate the purchase price allocation include reserve estimates of proved developed producing reserves acquired that are based on production forecasts, future commodity prices, future development costs and future production costs and assumptions associated with the Company's carry commitment.

The following table summarizes the recognizable assets acquired, liabilities assumed and consideration pursuant to the agreement:

Assets acquired and liabilities assumed		
Assets		
Property, plant and equipment	**$**	**56,447**
Liabilities		
Decommissioning and environmental liabilities		**(1,275)**
Net assets acquired	**$**	**55,172**
Deferred consideration		
Current obligation	**$**	**14,344**
Long-term obligation		**40,828**
Total deferred consideration	**$**	**55,172**

The deferred consideration represents the present value of the portion of the Company's future investment commitment attributable to the initial participating interest acquired. The liability will be accreted over the expected investment period, with the accretion recognized as a finance expense. As expenditures are incurred under the investment commitment, the corresponding portion of the deferred consideration liability will be settled.

9. 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 statements of net income and 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 nine month period ended September 30, 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	$	760,892
Net revenue less direct costs	$	440,210

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 net income and comprehensive income for the nine months ended September 30, 2025 includes $18.8 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the nine months ended September 30, 2025 attributable to the assets acquired since the LLA-32 Acquisition is $12.6 million.

10. Exploration and Evaluation Assets

Cost		
Balance at December 31, 2024	**$**	**116,928**
Additions and transfers from long-term inventory		109,730
Transfers to PP&E		(60,020)
Changes in decommissioning liability		5,627
Exploration and evaluation impairment		(11,140)
Balance at December 31, 2025	**$**	**161,125**
Additions and transfers from long-term inventory		147,414
Acquired on close of business combination - Note 8		11,089
Transfers to PP&E		(28,961)
Changes in decommissioning liability		11,872
Balance at September 30, 2026	**$**	**302,539**

Exploration and Evaluation ("E&E") assets consist of the Company's exploration projects which are pending either the determination of proved or probable reserves or impairment. Additions and transfers of $147.4 million for the nine months ended September 30, 2026 represent the Company's share of costs incurred on E&E assets during the period. During the nine months ended September 30, 2026, $29.0 million of E&E assets were transferred to PP&E related to Block LLA-111.

For the nine months ended September 30, 2026 $2.1 million of general and administrative costs (nine months ended September 30, 2025 - $1.8 million) have been capitalized in respect of exploration and evaluation activities during the current period.

At September 30, 2026 and December 31, 2025 the Company did not have any E&E assets in Canada.

At September 30, 2026 there were no indicators of impairment noted.

11. Property, Plant and Equipment

		Canada		Colombia		Total
Cost						
Balance at December 31, 2024	**$**	**21,432**	**$**	**3,756,897**	**$**	**3,778,329**
Additions and transfers from long-term inventory		1,340		199,255		200,595
Right-of-use-asset addition (non-cash)		—		4,338		4,338
Transfers from E&E assets		—		60,020		60,020
Additions related to property acquisition - Note 9		—		16,788		16,788
Changes in decommissioning and environmental liability		—		372		372
Balance at December 31, 2025	**$**	**22,772**	**$**	**4,037,670**	**$**	**4,060,442**
Additions and transfers from long-term inventory		415		238,677		239,092
Right-of-use-asset addition (non-cash) - Note 8		—		16,003		16,003
Transfers from E&E assets		—		28,961		28,961
Acquired on close of business combinations - Note 8		—		1,053,954		1,053,954
Changes in decommissioning and environmental liability		—		69,761		69,761
Balance at September 30, 2026	**$**	**23,187**	**$**	**5,445,026**	**$**	**5,468,213**
Accumulated Depreciation, Depletion and Amortization						
Balance at December 31, 2024	**$**	**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**	**$**	**2,560,229**
Depletion and depreciation for the period		1,541		210,762		212,303
Depreciation - Right-of-use-asset		562		1,357		1,919
DD&A included in crude oil inventory costing		—		(287)		(287)
Balance at September 30, 2026	**$**	**17,668**	**$**	**2,756,496**	**$**	**2,774,164**
Net book value:						
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
As at September 30, 2026	**$**	**5,519**	**$**	**2,688,530**	**$**	**2,694,049**

In the nine months ended September 30, 2026 property, plant and equipment ("PPE") additions of $239.1 million mainly relate to drilling and facility costs in Colombia. During the nine months ended September 30, 2026, $29.0 million of E&E assets were transferred to PP&E related to Block LLA-111.

For the nine months ended September 30, 2026 future development costs of $800.0 million (nine months ended September 30, 2025 - $346.4 million) were included in the depletion calculation for development and production assets. For the nine months ended September 30, 2026 $8.1 million of general and administrative costs (nine months ended September 30, 2025 - $5.0 million) have been capitalized in respect of development and production activities during the current period.

At September 30, 2026 there were no indicators of impairment noted, or indicators requiring a reversal of previously recorded impairments.

12. 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, 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**
Additions		10,698
Transfers to E&E and PP&E assets		(17,636)
Sale of inventory		(2,413)
Balance at September 30, 2026	**$**	**166,075**

For the nine months ended September 30, 2026, long-term inventory additions were $10.7 million, $17.6 million of long-term inventory was incorporated into the costs of E&E and PP&E projects and $2.4 million of inventory was sold. At September 30, 2026 there were no indicators of impairment noted.

13. Customer prepayments

	September 30, 2026	December 31, 2025
Current portion of customer prepayments	**$ 75,553**	$ —
Total customer prepayments	**$ 75,553**	$ —

In conjunction with the Frontera Transaction, the Company assumed all of Sabana's (formerly Frontera's) obligations under its customer prepayments. In December 2025, Sabana entered into a 24-month agreement with Chevron Products Company ("Chevron") to supply 500,000 barrels of crude oil per month. An advance payment of $80 million was received and recorded as a customer prepayment, to be recognized as revenue upon monthly deliveries. Under the agreement, the prepayment amounts will be subject to a financial discount calculated at SOFR plus 4.25% per annum.

As at September 30, 2026, customer prepayments are principally attributable to the advance payment received under the crude oil supply agreement described above. As at September 30, 2026, the carrying value for customer prepayments was $75.6 million. The Company invoked the early termination provision contained in the agreement by notifying Chevron of its decision to terminate the agreement, with such termination becoming effective on December 29, 2026 (the "Termination Date"). In accordance with the early termination provision, within fifteen (15) (fifteen) days following the Termination Date (that is, on or before January 13, 2027), the Company shall pay to the Chevron all outstanding costs, fees and any other amounts due and payable under the agreement. Accordingly, pursuant to paragraph 69(c) of IAS 1, the Company classified the entire outstanding balance of $75.6 million as a current liability as at September 30, 2026. This classification reflects the contractual settlement period resulting from the early termination of the agreement.

14. Debt

	September 30, 2026	December 31, 2025
2031 Unsecured notes	**$ 485,578**	$ —
2028 Unsecured notes	**307,311**	—
Total Unsecured notes	**792,889**	—
Credit facility	**82,499**	33,000
Total debt	**$ 875,388**	$ 33,000

Unsecured Notes

2031 Unsecured Notes

On May 11, 2026, in conjunction with the Frontera Transaction, the Company completed a $500.0 million private placement offering of senior unsecured notes due 2031 ("2031 Unsecured Notes") to fund the acquisition and for general corporate purposes. The notes were priced at par, bear interest at a rate of 8.50% per annum and mature on May 11, 2031, unless earlier redeemed or repurchased. The interest is payable semi-annually in arrears on November 11 and May 11 of each year, beginning on November 11, 2026. The carrying value for the 2031 Unsecured Notes as at September 30, 2026 was $485.6 million compared to the fair value of $501.3 million (Level 2 input). Net proceeds from the sale of the Notes were $484.6 million, after deducting the initial offering expenses payable by the Company of $15.4 million.

Key covenants include a fixed charge test of not less than 2.25:1 and net 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 key covenants at September 30, 2026.

2028 Unsecured Notes

In conjunction with the Frontera Transaction, the Company assumed all of Frontera's obligations under its $310.0 million aggregate principal amount of 7.875% senior unsecured notes due 2028 ("2028 Unsecured Notes") issued on June 21, 2021. The interest is payable semi-annually in arrears on June 21 and December 21 of each year, beginning on December 21, 2021. The 2028 Unsecured Notes will mature June 21, 2028, unless earlier redeemed or repurchased. The carrying value for the 2028 Unsecured Notes as at September 30, 2026 was $307.3 million compared to the fair value of $308.9 million (Level 2 input).

Key covenants include a fixed charge test of not less than 2.25:1 and net debt to adjusted EBITDA test of 3.25:1 and other standard business operating covenants for each reporting period. The Company was in compliance with all key covenants at September 30, 2026.

The 2028 and 2031 unsecured notes are subordinated to secured debt to the extent of the value of the assets securing such indebtedness.

Credit Facility

The Company has a senior secured credit facility with a syndicate of banks which at September 30, 2026 had a borrowing base of $240.0 million (December 31, 2025 - $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. At September 30, 2026, there was $82.5 million drawn on the credit facility (at December 31, 2025 - $33.0 million was drawn). The undrawn capacity on the credit facility at September 30, 2026 was $157.5 million (December 31, 2025 - $207.0 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 a final maturity date of May 31, 2028. The next annual review is scheduled to occur in May 2027.

Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3.50:1, senior secured debt to adjusted EBITDA test of 3.00:1, and other standard business operating covenants for each reporting period. The Company was in compliance with all key covenants at September 30, 2026.

Refer to note 27 – Commitments and Contingencies for details regarding performance guarantees in place with the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petróleos S.A. ("Ecopetrol") in respect of exploration work commitments on the Company's Colombian concessions. These guarantees have been provided in the form of unsecured letters of credit issued by select Latin American banks with varying terms and are reduced from time to time to reflect work performed on the various blocks.

15. Lease Obligations

	Canada	Colombia	Total
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**
Acquired on close of business combination - Note 8	—	16,003	16,003
Interest expense	23	1,148	1,171
Lease payments	(539)	(5,380)	(5,919)
Foreign exchange loss (gain)	(133)	701	568
Balance at September 30, 2026	**$ 3,029**	**$ 17,939**	**$ 20,968**
Current obligation	(763)	(3,413)	(4,176)
Long-term obligation	**$ 2,266**	**$ 14,526**	**$ 16,792**

In connection with the Frontera Transaction, the Company assumed Frontera's obligations under its existing lease arrangements. The leases relate to various properties, vehicles, power generation supply, including the arrangements associated to the CPE-6 Solar Plant and CPE-6 Battery Energy Storage System, and other assets.

16. Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2024	$ 68,469	$ 9,206	$ 77,675
Additions	6,407	3,275	9,682
Property acquisitions - Note 9	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
Additions	17,030	2,827	19,857
Acquired on close of business combinations - Note 8	157,524	23,750	181,274
Discount rate adjustment on obligations acquired	32,355	5,894	38,249
Settlements of obligations during the period	(18,866)	(4,802)	(23,668)
Loss on settlement of obligations	104	—	104
Accretion expense	14,935	1,841	16,776
Change in estimate - inflation and discount rates	2,053	1,672	3,725
Change in estimate - costs and timing of settlements	17,567	2,235	19,802
Foreign exchange loss	9,879	4,033	13,912
Balance, September 30, 2026	**$ 310,144**	**$ 49,052**	**$ 359,196**
Current obligation	(11,130)	(7,840)	(18,970)
Long-term obligation	**$ 299,014**	**$ 41,212**	**$ 340,226**

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 September 30, 2026, the estimated costs to abandon and reclaim the wells, well sites and facilities 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 $711.7 million as at September 30, 2026 (December 31, 2025 – $244.5 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.4% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the decommissioning liability is $11.1 million (December 31, 2025 – $7.3 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 $106.1 million as at September 30, 2026 (December 31, 2025 – $29.7 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.4% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the environmental liability is $7.8 million (December 31, 2025 – $2.8 million) that is classified as a current obligation.

17. 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.

CosRSU:	Number of CosRSUs	Weighted average exercise price Cdn$/ CosRSU
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	—
Granted[1]	529,547	—
Exercised	(645,956)	—
Forfeited	(113,660)	—
Balance, September 30, 2026	**1,266,366**	**—**

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

CosPSU:	Number of CosPSUs	Weighted average exercise price Cdn$/ CosPSU
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	—
Granted[1]	72,214	—
Granted by performance factor	235,720	—
Exercised	(532,633)	—
Forfeited	(68,555)	—
Balance, September 30, 2026	**254,845**	**—**

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

As at September 30, 2026 and 2025, no CosRSUs and CosPSUs were vested.

The weighted average fair value at the grant date for the nine months ended September 30, 2026 was Cdn$23.14 per CosRSU and CosPSU (nine months ended September 30, 2025 - Cdn$14.78 per CosRSU and CosPSU). The weighted average share price on the exercise date for CosRSUs and CosPSUs exercised during the nine months ended September 30, 2026 was Cdn$22.33 (nine months ended September 30, 2025 – Cdn$13.65).

Pursuant to the cash or share settled restricted share unit and performance share unit plan, the Company has granted cash or share settled 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 pre-determined adjustment factor of between 0-2x is applied to CosPSUs eligible to vest at the end of the performance period. In March 2026 the board of directors approved a multiplier of 1.67X be applied to the 2023 CosPSU grant resulting in 235,720 CosPSUs issued. 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.

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 September 30, 2026, the total CosRSUs and CosPSUs liability accrued is $14.4 million (December 31, 2025 - $18.8 million) of which $4.7 million (December 31, 2025 - $4.5 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 the new 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 ten years from the date of grant. LDPSUs vest three years after the grant date and expire ten years after the grant date.

LDRSU:	Number of LDRSUs	Weighted average exercise price Cdn$/ LDRSU
Balance, December 31, 2024	102,495	—
Granted[(1)]	208,953	—
Balance, December 31, 2025	311,448	—
Granted[(1)]	110,146	—
Exercised	(14,500)	—
Balance, September 30, 2026	**407,094**	**—**

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

LDPSU:	Number of LDPSUs	Weighted average exercise price Cdn$/ LDPSU
Balance, December 31, 2024	208,577	—
Granted[(1)]	414,321	—
Balance, December 31, 2025	622,898	—
Granted[(1)]	221,541	—
Balance, September 30, 2026	**844,439**	**—**

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

As at September 30, 2026 133,242 LDRSUs and no LDPSUs were vested. As at September 30, 2025 37,626 LDRSUs and no LDPSUs were vested.

The weighted average fair value at the grant date for the nine months ended September 30, 2026 was Cdn$26.32 per LDRSU and LDPSU (nine months ended September 30, 2025 - Cdn$12.75 per LDRSU and LDPSU). The weighted average share price on the exercise date for LDRSUs exercised during the nine months ended September 30, 2026 was Cdn$25.30.

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 ten 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 September 30, 2026, the total LDRSUs and LDPSUs liability accrued is $10.6 million (December 31, 2025 - $4.0 million) of which $3.3 million (December 31, 2025 - $2.8 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 DSUs	Weighted average exercise price Cdn$/ DSU
Balance, December 31, 2024	348,812	—
Granted[(1)]	128,621	—
Exercised	(68,767)	—
Balance, December 31, 2025	408,666	—
Granted[(1)]	46,972	—
Exercised	(137,929)	—
Balance, September 30, 2026	**317,709**	—

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

The weighted average fair value at the grant date for the nine months ended September 30, 2026 was $27.81 per DSU (nine months ended September 30, 2025 - Cdn$10.88 per DSU). The weighted average share price on the exercise date for DSUs exercised during the nine months ended September 30, 2026 was Cdn$24.87 (nine months ended September 30, 2025 - Cdn$17.98).

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 September 30, 2026, the total DSUs liability accrued is $6.0 million (December 31, 2025 - $5.5 million) of which $6.0 million (December 31, 2025 - $4.5 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 CRSUs 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, 2024	810,676	—
Granted[(1)]	1,008,076	—
Exercised	(371,742)	—
Forfeited	(88,248)	—
Balance, December 31, 2025	1,358,762	—
Granted[(1)]	510,323	—
Exercised	(552,158)	—
Forfeited	(98,026)	—
Balance, September 30, 2026	**1,218,901**	**—**

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

As at September 30, 2026 and 2025, no CRSUs were vested given that they exercise once vested.

The weighted average fair value at the grant date for nine months ended September 30, 2026 was Cdn$23.14 per CRSU (nine months ended September 30, 2025 - Cdn$14.79 per CRSU). The weighted average share price on the exercise date for CRSUs exercised for the nine months ended September 30, 2026 was Cdn$21.90 (nine months ended September 30, 2025 – Cdn$13.98).

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 September 30, 2026, the total CRSUs liability accrued is $11.5 million (December 31, 2025 - $9.3 million) of which $3.6 million (December 31, 2025 - $3.4 million) is classified as long-term in accordance with the three-year vesting period.

e) Cash settled share-based compensation

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
CosRSUs and CosPSUs expense	**$ 5,630**	$ 5,536	**$ 14,204**	$ 10,165
LDRSUs and LDPSUs expense	**3,754**	1,446	**6,863**	2,277
DSUs expense	**1,360**	1,538	**2,956**	2,681
CRSUs expense	**4,578**	3,213	**9,186**	4,816
Total cash settled share-based compensation expense	**$ 15,322**	$ 11,733	**$ 33,209**	$ 19,939
Cash payments made upon exercise in the period	**$ 858**	$ 1,047	**$ 30,435**	$ 12,279

18. Share Capital

a) Issued and outstanding common shares

	Number of shares		Amount
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
Issued for cash - exercise of options	221,764		3,137
Allocation of contributed surplus – exercise of options	—		785
Balance, September 30, 2026	**96,195,900**	**$**	**624,984**

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

In the nine months ended September 30, 2026, there were 221,764 options exercised for proceeds of $3.1 million (year ended December 31, 2025 - no options were exercised). For the nine months ended September 30, 2026, the Company did not repurchase any common shares pursuant to its Normal Course Issuer Bid.

For the year ended December 31, 2025, the Company repurchased 2,364,900 common shares pursuant to its Normal Course Issuer Bid at a cost of $26.5 million (average cost per share of Cdn$15.37). 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 2026 were $80.2 million or Cdn$1.155 per share (for the year ended December 31, 2025 - $107.7 million or Cdn$1.54 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 stock options	Weighted average exercise price Cdn$/option
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
Granted	341,386	25.72
Exercised	(221,764)	19.51
Forfeited	(168,583)	20.97
Balance, September 30, 2026	**1,204,647**	**20.21**

Stock options outstanding and the weighted average remaining life of the stock options at September 30, 2026 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	430,057	3.43	$ 12.74	93,774	3.43	$ 12.74
$16.91 - $21.92	191,082	2.43	$ 21.06	113,923	2.43	$ 21.06
$21.93 - $25.60	113,614	1.34	$ 22.81	113,614	1.34	$ 22.81
$25.61 - $26.37	341,386	4.45	$ 25.72	—	—	$ —
$26.38 - $27.02	128,508	0.36	$ 27.02	128,508	0.36	$ 27.02
	1,204,647	**3.04**	**$ 20.21**	**449,819**	**1.77**	**$ 21.47**

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 nine months ended September 30,	**2026**	2025
Risk-free interest rate (%)	**2.94**	2.66
Expected life (years)	**4**	4
Expected volatility (%)	**41**	41
Forfeiture rate (%)	**3**	3
Expected dividend yield (%)	**5.77**	8.47

The weighted average fair value at the grant date for the nine months ended September 30, 2026 was Cdn$5.76 per option (nine months ended September 30, 2025 - Cdn$1.68 per option). In the nine months ended September 30, 2026, there were 221,764 options exercised. The weighted average share price on the exercise date for options exercised in the nine months ended September 30, 2026 was $27.14.

c) Equity settled share-based compensation

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Option expense	**$ 273**	$ 169	**$ 712**	$ 531
Total equity settled share-based compensation expense	**$ 273**	$ 169	**$ 712**	$ 531

19. 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 three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Crude oil	**$ 616,070**	$ 244,003	**$ 1,333,600**	$ 736,345
Natural gas	**17,479**	8,421	**37,342**	20,784
Oil and natural gas sales	**$ 633,549**	$ 252,424	**$ 1,370,942**	$ 757,129

At September 30, 2026, receivables from contracts with customers, which are included in accounts receivable, were $158.1 million (December 31, 2025 - $72.3 million).

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Other revenue	**$ 1,971**	$ 2,168	**$ 6,635**	$ 6,999

20. Other Expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Other Colombian taxes	**$ 2,208**	$ 2,772	**$ 4,411**	6,098
Colombian tax credit purchased	**—**	—	**—**	8,097
Equity tax	**—**	—	**6,288**	—
Legal provisions	**(1,339)**	—	**180**	—
Loss (gain) on settlement of decommissioning liabilities	**1,325**	(6)	**104**	539
Loss (gain) on disposition of tangible assets	**(1,645)**	46	**2,726**	81
Site restoration costs	**2,013**	—	**12,816**	—
Insurance proceeds	**(2,000)**	—	**(2,000)**	—
Other	**1,215**	1,003	**3,579**	2,600
Total other expense	**$ 1,777**	$ 3,815	**$ 28,104**	$ 17,415

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Non-cash other expense (income)	**$ (1,397)**	$ 40	**$ 3,857**	$ 620
Cash other expense	**3,174**	3,775	**24,247**	16,795
Total other expense	**$ 1,777**	$ 3,815	**$ 28,104**	$ 17,415

On February 24, 2026, through Executive Order 0173, the Colombian Government created a new equity tax applicable for fiscal year 2026. The tax applies to legal entities and de facto partnerships that are income tax filers in Colombia. The tax is assessed and becomes payable on equity as of March 1, 2026 equal to or exceeding 200,000 tax unit's value (UVT) (approximately COP$10.5 billion or US$2.7 million) at rates from 0.5% to 1.6%. This Executive Order will be challenged through the Constitutional Court and it may or may not be overturned by the Court. The equity tax payable was settled by June 30, 2026.

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.

A provision has been recognized for the estimated costs required for site restoration in accordance with applicable regulations and contractual obligations. Management expects that a portion of these restoration costs will be recovered through insurance arrangements. Insurance recoveries are recognized only when recovery is virtually certain. For the three and nine months ended September 30, 2026 $2.0 million has been approved by the insurers.

21. Net Finance Expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Bank charges and credit facility fees	**$ 2,546**	$ 1,646	**$ 4,772**	$ 3,837
Interest on bank debt	**2,206**	431	**7,032**	1,665
Interest on senior unsecured notes	**15,427**	—	**23,280**	—
Amortization of deferred financing charges	**1,256**	—	**1,590**	—
Accretion on decommissioning and environmental liabilities	**10,508**	111	**16,776**	6,649
Interest and other income	**(1,781)**	(1,306)	**(7,925)**	(3,215)
Lease obligation interest expense	**724**	48	**1,171**	141
Expected credit loss provision	**501**	3,451	**1,114**	3,302
Other	**3,113**	109	**4,530**	732
Net finance expense	**$ 34,500**	$ 4,490	**$ 52,340**	$ 13,111

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Non-cash finance expense	**$ 12,598**	$ 3,566	**$ 19,480**	$ 9,952
Cash finance expense	**21,902**	924	**32,860**	3,159
Net finance expense	**$ 34,500**	$ 4,490	**$ 52,340**	$ 13,111

22. Net Income per Share

a) Basic net income per share

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Net income				
Net income for the purpose of basic net income per share	**$ 75,255**	$ 50,476	**$ 524,140**	$ 180,218
Weighted average number of shares for the purposes of basic net income per share (000s)	**96,185**	96,874	**96,119**	97,492
Basic net income per share	**$ 0.78**	$ 0.52	**$ 5.45**	$ 1.85

b) Diluted net income per share

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Net income				
Net income used to calculate diluted net income per share	**$ 75,255**	$ 50,476	**$ 524,140**	$ 180,218
Weighted average number of shares for the purposes of basic net income per share (000s)	**96,185**	96,874	**96,119**	97,492
Dilutive effect of stock options on potential common shares	**255**	82	**233**	9
Weighted average number of shares for the purposes of diluted net income per share (000s)	**96,440**	96,956	**96,352**	97,501
Diluted net income per share	**$ 0.78**	$ 0.52	**$ 5.44**	$ 1.85

For the three and nine months ended September 30, 2026, 469,894 and 471,740 stock options (three and nine months ended September 30, 2025 - 749,097 and 872,563 stock options) were excluded from the diluted weighted average shares calculation as they were anti-dilutive.

23. 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:

	As at September 30,		As at June 30,		As at December 31,	
	2026	2025	2026	2025	2025	2024
Cash and cash equivalents	**$ 142,725**	$ 69,810	$ 163,286	$ 98,825	$ 58,328	$ 98,022
Restricted cash and cash equivalents - current	**6,418**	634	6,120	597	5,424	581
Restricted cash and cash equivalents - long-term[(1)]	**12,520**	4,331	12,846	4,078	191	3,184
	$ 161,663	$ 74,775	$ 182,252	$ 103,500	$ 63,943	$ 101,787

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

b) Net change in assets and liabilities

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Accounts receivable	**$ (77,408)**	$ (17,409)	**$ (66,470)**	$ 503
Prepaids and other current assets	**15,151**	8,601	**4,183**	10,272
Short-term inventory	**(21,378)**	27	**(299)**	1,835
Current income tax receivable/payable	**(15,275)**	(6,370)	**(30,134)**	(16,353)
Accounts payable and accrued liabilities	**4,503**	3,307	**1,970**	29,936
Customer prepayments	**(4,447)**	—	**(4,747)**	—
Depletion related to oil inventory	**(104)**	(10)	**(287)**	(556)
Decommissioning and environmental liabilities	**(12,604)**	(2,347)	**(23,668)**	(6,567)
Net change in assets and liabilities	**$ (111,562)**	$ (14,201)	**$ (119,452)**	$ 19,070
Operating	**$ (58,113)**	$ (18,306)	**$ (80,548)**	$ (15,051)
Investing	**(53,449)**	3,959	**(38,904)**	35,203
Financing	**—**	146	**—**	(1,082)
Net change in assets and liabilities	**$ (111,562)**	$ (14,201)	**$ (119,452)**	$ 19,070

c) Interest and taxes paid

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Cash interest paid	**$ 3,510**	$ 303	**$ 19,171**	$ 1,985
Cash income taxes paid	**$ —**	$ 650	**$ —**	$ 650

24. Capital Management

The Company's objective when managing capital is to maintain a strong capital base that provides financial flexibility to fund operations, execute its business strategy and maintain the confidence of investors, lenders and other capital providers.

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 to include shareholders' equity, the credit facility, unsecured notes and its working capital. As at September 30, 2026 shareholders' equity was $2,400.5 million (December 31, 2025 - $1,952.9 million).

The Company has a senior secured credit facility with a syndicate of banks with a borrowing base of $240.0 million at September 30, 2026 (December 31, 2025 - $240.0 million). The credit facility is intended to provide additional liquidity and fund cash or letter of credit needs as they arise. As at September 30, 2026 there was $82.5 million drawn on the credit facility (December 31, 2025 - $33.0 million).

Refer to note 14 - Debt for details regarding the Company's senior secured credit facility and senior unsecured notes.

Refer to note 27 – Commitments and Contingencies for details regarding performance guarantees in place with the ANH and Ecopetrol in respect of exploration work commitments on the Company's Colombian concessions. These guarantees have been provided in the form of unsecured letters of credit issued by select Latin American banks with varying terms and are reduced from time to time to reflect work performed on the various blocks.

As at September 30, 2026, the Company's net working capital deficit was $36.0 million (December 31, 2025 - $28.0 million surplus).

The Company is subject to financial covenants under its senior secured credit facility and senior unsecured notes. As at September 30, 2026, the Company was in compliance with all externally imposed capital requirements.

25. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash and cash equivalents, accounts receivable, marketable securities, accounts payable and accrued liabilities, customer prepayments, the senior secured credit facility and senior unsecured notes. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to the short-term nature of these instruments. The fair value of the revolving credit facility approximates its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates. The fair value of the senior unsecured notes is determined based on quoted market prices and other observable market inputs and is classified as Level 2 within the fair value hierarchy. Refer to note 14 - Debt for the carrying values and fair values of the Company's senior unsecured notes as at September 30, 2026.

As at September 30, 2026, 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 $22.8 million.

a) Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The Company's exposure to credit risk primarily arises from cash and cash equivalents and accounts receivable from joint venture partners and oil marketing counterparties.

The Company manages credit risk related to cash and cash equivalents by maintaining balances with reputable financial institutions, monitoring the creditworthiness of banking counterparties, and assessing counterparty exposure.

The Company manages credit risk associated with accounts receivable by assessing the financial strength and creditworthiness of oil marketing counterparties and joint venture partners, monitoring outstanding balances, and evaluating the collectability of amounts owed to the Company.

For the nine months ended September 30, 2026 the Company had the majority of its oil sales to two counterparties. The accounts receivable balance as at September 30, 2026 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. At September 30, 2026, there were no accounts receivable past due (December 31, 2025 - $nil). None of the Company's receivables are impaired at September 30, 2026. 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 maintain sufficient cash balances, cash flows from operations, available credit facilities and access to debt to meet its obligations as they become due. Management prepares cash flow forecasts for a period of 12 to 36 months to identify any financing requirements and monitor liquidity. 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. During the nine months ended September 30, 2026, the Company issued $500.0 million aggregate principal amount of 8.50% senior unsecured notes due 2031. In addition, as at September 30, 2026, there was $82.5 million drawn on the Company's $240.0 million senior secured credit facility (December 31, 2025 - $33.0 million was drawn).

The following are the contractual maturities of financial liabilities at September 30, 2026:

	Less than 1 year	1-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	$ 587,846	—	—	31,479	$ 619,325
Bank debt including interest	—	93,543	—	—	93,543
Unsecured notes, including interest	66,913	419,414	585,000	—	1,071,327
Customer prepayments	75,553	—	—	—	75,553
Lease obligation	4,176	16,792	—	—	20,968
Cash settled share-based compensation payable	24,763	17,676	—	—	42,439
Total	**$ 759,251**	**547,425**	**585,000**	**31,479**	**$ 1,923,155**

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**

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 September 30, 2026, the Company had no crude oil risk management contracts in place. The Company is currently unhedged for the remainder of 2026, with full exposure to changes in commodity prices.

The table below summarizes the loss on the commodity risk management contracts that were in place during the three and nine months ended September 30, 2026 and 2025:

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Realized loss (gain) on commodity risk management contracts	**$ —**	$ —	**$ 32,946**	$ (3,337)
Premiums paid on commodity risk management contracts	**—**	3,193	**—**	6,723
Unrealized gain on commodity risk management contracts	**—**	(172)	**(1,281)**	(1,332)
Total loss	**$ —**	$ 3,021	**$ 31,665**	$ 2,054

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 September 30, 2026, the Company had the following foreign currency risk management contracts in place:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP	Max Compensation
September 15, 2026 to December 15, 2026	COP	Collar with limited compensation	$27,000,000	3,700-4,200	800
September 19, 2026 to December 15, 2026	COP	Costless collar	$45,000,000	3,400-3,663	N/A
October 15, 2026 to December 15, 2026	COP	Costless collar	$75,000,000	3,200-3,475	N/A
January 6, 2027 to March 17, 2027	COP	Costless collar	$45,000,000	3,350-3,539	N/A
April 7, 2027 to June 23, 2027	COP	Costless collar	$45,000,000	3,350-3,701	N/A
July 7, 2027 to September 30, 2027	COP	Costless collar	$45,000,000	3,350-3,825	N/A
October 1, 2027 to December 31, 2027	COP	Costless collar	$45,000,000	3,350-4,025	N/A

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three and nine months ended September 30, 2026 and 2025 which is recorded in the financial statement line item "Foreign exchange gain" in the consolidated statements of net income and comprehensive income:

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Realized gain on foreign currency risk management contracts	**$ (9,248)**	$ (3,193)	**$ (11,025)**	$ (4,418)
Unrealized (gain) loss on foreign currency risk management contracts	**(334)**	680	**(4,441)**	(3,452)
Total gain	**$ (9,582)**	$ (2,513)	**$ (15,466)**	$ (7,870)

26. Segmented Information

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

For the three months ended September 30, 2026	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 633,549	$ 633,549
Royalties	—	(86,452)	(86,452)
Net revenue	—	547,097	547,097
Other revenue	—	1,971	1,971
Revenue	—	549,068	549,068
Expenses			
Production	—	165,039	165,039
Transportation	—	53,667	53,667
Purchased crude oil	—	50,712	50,712
General and administrative	12,539	23,251	35,790
Unrealized gain on marketable securities	(8,215)	—	(8,215)
Loss on acquisition	4,873	—	4,873
Depletion, depreciation and amortization	568	99,983	100,551
Cash settled share-based compensation expense	10,744	4,578	15,322
Equity settled share-based compensation expense	273	—	273
Other expense	—	1,777	1,777
Foreign exchange gain	(133)	(10,848)	(10,981)
	20,649	388,159	408,808
Finance income	(204)	(1,577)	(1,781)
Finance expense	18,961	17,320	36,281
Net finance expense	18,757	15,743	34,500
Income (loss) before taxes	(39,406)	145,166	105,760
Current tax expense	4,245	12,362	16,607
Deferred tax expense (recovery)	(9,156)	23,054	13,898
Net income (loss)	**$ (34,495)**	**$ 109,750**	**$ 75,255**
Other comprehensive loss			
Foreign currency translation	—	(198)	(198)
Total comprehensive income (loss) for the period	**$ (34,495)**	**$ 109,552**	**$ 75,057**
Capital assets (end of period)	$ 5,519	$ 2,991,069	$ 2,996,588
Capital expenditures	$ 4	$ 161,766	$ 161,770
Total assets (end of period)	$ 101,260	$ 4,352,752	$ 4,454,012

For the three months ended September 30, 2025	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 252,424	$ 252,424
Royalties	—	(30,785)	(30,785)
Net revenue	—	221,639	221,639
Other revenue	—	2,168	2,168
Commodity risk management contracts loss	—	(3,021)	(3,021)
Revenue	—	220,786	220,786
Expenses			
Production	—	62,120	62,120
Transportation	—	19,124	19,124
General and administrative	8,823	10,391	19,214
Depletion, depreciation and amortization	725	47,042	47,767
Cash settled share-based compensation expense	8,520	3,213	11,733
Equity settled share-based compensation expense	169	—	169
Other expense	—	3,815	3,815
Foreign exchange gain	(2,004)	(3,218)	(5,222)
	16,233	142,487	158,720
Finance income	(34)	(1,272)	(1,306)
Finance expense	1,517	4,279	5,796
Net finance expense	1,483	3,007	4,490
Income (loss) before taxes	(17,716)	75,292	57,576
Current tax expense	900	10,235	11,135
Deferred tax recovery	(1,523)	(2,512)	(4,035)
Net income (loss)	**$ (17,093)**	**$ 67,569**	**$ 50,476**
Capital assets (end of period)	$ 7,223	$ 1,635,042	$ 1,642,265
Capital expenditures	$ 315	$ 79,646	$ 79,961
Total assets (end of period)	$ 29,140	$ 2,231,391	$ 2,260,531

For the nine months ended September 30, 2026	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 1,370,942	$ 1,370,942
Royalties	—	(196,201)	(196,201)
Net revenue	—	1,174,741	1,174,741
Other revenue	—	6,635	6,635
Commodity risk management contracts loss	—	(31,665)	(31,665)
Revenue	—	1,149,711	1,149,711
Expenses			
Production	—	313,121	313,121
Transportation	—	107,943	107,943
Purchased crude oil	—	87,468	87,468
General and administrative	32,575	49,054	81,629
Unrealized gain on marketable securities	(18,500)	—	(18,500)
Transaction costs	29,000	—	29,000
Gain on acquisition	(297,610)	—	(297,610)
Depletion, depreciation and amortization	2,103	212,119	214,222
Cash settled share-based compensation expense	24,023	9,186	33,209
Equity settled share-based compensation expense	712	—	712
Other expense	885	27,219	28,104
Foreign exchange loss (gain)	289	(13,519)	(13,230)
	(226,523)	792,591	566,068
Finance income	(2,131)	(5,794)	(7,925)
Finance expense	32,787	27,478	60,265
Net finance expense	30,656	21,684	52,340
Income before taxes	195,867	335,436	531,303
Current tax expense (recovery)	(2,158)	36,725	34,567
Deferred tax recovery	(8,084)	(19,320)	(27,404)
Net income	**$ 206,109**	**$ 318,031**	**$ 524,140**
Other comprehensive loss			
Foreign currency translation	—	(198)	(198)
Total comprehensive income for the period	**$ 206,109**	**$ 317,833**	**$ 523,942**
Capital assets (end of period)	$ 5,519	$ 2,991,069	$ 2,996,588
Capital expenditures	$ 415	$ 386,091	$ 386,506
Total assets (end of period)	$ 101,260	$ 4,352,752	$ 4,454,012

For the nine months ended September 30, 2025	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 757,129	$ 757,129
Royalties	—	(98,103)	(98,103)
Net revenue	—	659,026	659,026
Other revenue	—	6,999	6,999
Commodity risk management contracts loss	—	(2,054)	(2,054)
Revenue	—	663,971	663,971
Expenses			
Production	—	168,470	168,470
Transportation	—	53,363	53,363
Purchased crude oil	—	162	162
General and administrative	24,610	29,059	53,669
Depletion, depreciation and amortization	2,235	143,900	146,135
Cash settled share-based compensation expense	15,123	4,816	19,939
Equity settled share-based compensation expense	531	—	531
Other expense	—	17,415	17,415
Foreign exchange gain	(337)	(8,506)	(8,843)
	42,162	408,679	450,841
Finance income	(248)	(2,967)	(3,215)
Finance expense	4,374	11,952	16,326
Net finance expense	4,126	8,985	13,111
Income (loss) before taxes	(46,288)	246,307	200,019
Current tax expense (recovery)	(239)	32,506	32,267
Deferred tax recovery	(1,423)	(11,043)	(12,466)
Net income (loss)	**$ (44,626)**	**$ 224,844**	**$ 180,218**
Capital assets (end of period)	$ 7,223	$ 1,635,042	$ 1,642,265
Capital expenditures	$ 539	$ 225,166	$ 225,705
Total assets (end of period)	$ 29,140	$ 2,231,391	$ 2,260,531

For the three months ended September 30, 2026, the Company had two external customers (three months ended September 30, 2025 - 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 $396.9 million for the three months ended September 30, 2026 and $238.0 million for the three months ended September 30, 2025.

For the nine months ended September 30, 2026, the Company had two external customers (nine months ended September 30, 2025 - 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 $921.9 million for the nine months ended September 30, 2026 and $573.3 million for the nine months ended September 30, 2025.

27. Commitments and Contingencies

The value of the Company's commitments as at September 30, 2026 for contracts that were in place were as follows:

	2026	2027	2028	2029	2030	Thereafter	Total
Minimum work commitments	$ 38,261	$ 141,777	$ 101,524	$ 78,789	$ —	$ 637,974	$ 998,325
Transportation	7,205	2,554	—	—	—	—	9,759
Operating leases	639	2,424	741	—	—	—	3,804
Other commitments							
Purchased oil	24,738	—	—	—	—	—	24,738
Energy supply commitments	11,071	12,890	13,512	9,631	9,920	10,206	67,230
Total	**$ 81,914**	**$ 159,645**	**$ 115,777**	**$ 88,420**	**$ 9,920**	**$ 648,180**	**$1,103,856**

Minimum work commitments

The value of the Company's commitments as at September 30, 2026 in respect of the Colombia work commitments under E&P contracts, joint venture farm-in arrangements and business collaboration agreements are as disclosed above. At September 30, 2026, performance guarantees to support the work commitments on the Company's Colombian concessions were in place with the ANH and Ecopetrol joint venture blocks in the amount of $505.0 million (December 31, 2025 - $235.1 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.

The value of the Company's exploration commitments as at September 30, 2026 in respect of the Colombia work commitments under E&P contracts, and joint venture farm-in arrangements, is as disclosed above.

Transportation

Includes ship-or-pay contracts with Bicentenario and Cenit where the pledged inventory crude oil is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. A pledge agreement with Ocensa and Cenit is in place, which guarantees the payment obligations of both contracts.

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 September 30, 2026 are as disclosed above.

Purchased oil

Includes an agreement in place covering crude oil purchases for 2026.

Energy supply

Includes executed contracts for grid-connected, on-site generation, and solar power sources, ensuring the electricity supply across operational blocks, particularly Quifa and CPE-6.

Contingencies

The Company is involved in various legal, regulatory and administrative claims, and proceedings arising from the normal course of business. Given that the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. Management has assessed the likelihood of settlement and determined the best estimate based on relevant information and the probability of outcomes. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

Refer to Note 8 - Business Combinations regarding the contingent payment agreed to as part of the consideration of the Frontera Transaction.

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 period ended September 30, 2026 is dated November 5, 2026 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the period ended September 30, 2026, as well as the Company's audited consolidated annual financial statements for the year ended December 31, 2025. The unaudited condensed interim consolidated financial statements and the audited consolidated annual 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 ("AIF"), and may be accessed through the SEDAR+ website at www.sedarplus.ca.

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

Company Profile

Parex is the largest independent oil and gas company in Colombia, focusing on sustainable, conventional production. The Company's corporate headquarters are in Calgary, Canada, with an operating office in Bogotá, Colombia. Parex's 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 crude oil 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*.

Three months ended September 30, 2026 ("third quarter" or "Q3") Highlights

- Recognized the first full-quarter results of the Colombian exploration and production assets acquired from Frontera Energy Corporation ("Frontera Transaction"), demonstrating their successful initial integration into the Company's operations.
- Crude oil and natural gas production averaged 83,264 boe/d in the third quarter of 2026, an increase of 89% compared to the third quarter of 2025 average production of 43,953 boe/d. The step change was primarily driven by the first full-quarter of production from the assets acquired in the Frontera Transaction, which closed on June 1, 2026 and continued strong production from the Eastern Llanos. Refer to "Consolidated Results of Operations" for production split by product type.
- Recognized net income of $75.3 million ($0.78 per share basic) compared to net income of $50.5 million ($0.52 per share basic) in the third quarter of 2025. The increase was primarily attributed to the increased operating netback, driven by higher volumes and crude oil prices.
- Generated quarterly funds flow provided by operations ("FFO")[(1)] of $196.3 million ($2.04 per share basic[(2)]) compared to $105.3 million ($1.09 per share basic[(2)]) in the third quarter of 2025. The increase is primarily attributed to the increase in production from the newly acquired assets, newly added crude oil production in the Llanos Basin, an increase in gas production in the Magdalena Basin and higher realized prices. A build in crude oil inventories of 316,900 bbls resulted in an estimated $10.0 million temporary FFO impact, with the volumes sold post-Q3.
- Generated an operating netback[(2)] of $37.25/boe (Q3 2025 - $34.71/boe) and an FFO netback[(2)] of $26.33/boe (Q3 2025 - $26.04/boe[(2)]) from an average Brent price of $91.29/bbl (Q3 2025 - $68.17/bbl).
- Incurred $161.8 million of capital expenditures[(3)] compared to $80.0 million in the third quarter of 2025.
- Paid a regular quarterly dividend of C$0.385 per share[(4)].

(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".

Corporate Guidance

The Company is updating its H2 2026 guidance to reflect operating performance to date and its latest expectations for the balance of the year. Production remains in line with expectations, allowing the Company to narrow its H2 2026 production guidance range while maintaining the midpoint at 86,500 boe/d.

The revised outlook reflects evolving market conditions, including movements in benchmark oil prices and wider differentials across Brent, WTI and Colombia's Vasconia benchmark. The current commodity price environment is also influencing operating costs, with higher oil prices driving increased diluent and diesel expenses, El Niño-related seasonal conditions raising power generation costs, and Colombian peso appreciation contributing to higher production expenses. Under more normalized market conditions, the Company would expect crude oil differentials and operating costs to moderate.

To manage a portion of its exposure to currency movements, the Company has implemented Colombian peso collars covering approximately 50% of its Colombian peso-denominated costs for Q4 2026 and has begun building a hedge position for 2027. In parallel, following the Frontera Transaction, the Company continues to advance operational integration and assess opportunities to optimize its operating model and realize efficiencies over time.

These measures and market considerations are reflected in the Company's updated expectations for realized pricing and operating costs for the remainder of 2026. Partially offsetting these pressures, the Company expects improvements in its projected effective tax rate, providing a benefit to the financial outlook.

The Company's revised outlook also reflects increased capital investment to support ongoing development activities in the Middle Magdalena (Llanito and Casabe) and advance exploration successes in the Eastern Llanos (LLA-111) and Lower Magdalena (VIM-1). This investment will support the advancement of farm-in commitments and progress infrastructure required to capitalize on positive exploration results, positioning the Company to support its 2027 outlook and longer-term growth objectives.

Category	**H2 2026 Guidance** (May 12, 2026)	**Updated H2 2026 Guidance** (November 6, 2026)
Brent Crude Oil Average Price	$90/bbl	$95/bbl
Average Production	82,000-91,000 boe/d	85,500-87,500 boe/d
Funds Flow Provided by Operations Netback[(1)]	$30-33/boe	$27-29/boe
Funds Flow Provided by Operations[(2)]	$475-525 million	$435-450 million
Capital Expenditures[(3)]	$275-295 million	$285-315 million
Free Funds Flow[(3)]	$215 million (midpoint)	$140 million (midpoint)

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

The following table summarizes the key assumptions underlying the Company's updated H2 2026 guidance:

Category	**H2 2026 Guidance** (May 12, 2026)	**Updated H2 2026 Guidance [(1)]** (November 6, 2026)
Differential (Vasconia)	$4.00/bbl	$8.00-12.00/bbl
Production Expense (Opex + Energy)	$16.00-20.00/boe	$22.00-23.00/boe
Effective Tax Rate	12-15%	7-10%

(1) All other key H2 2026 assumptions unchanged: operational downtime: ~5%; transportation expense: ~$7.50/boe; G&A expense: ~$5.00/boe; finance expense: ~$2.50/boe; see "Non-GAAP and Other Financial Measures Advisory".

For FY 2026, average production is expected to exceed the previous guidance range of 63,000 to 67,000 boe/d, while capital expenditures guidance is increased to $510 to $540 million.

Refer to "Business Combination" for details on the Frontera Transaction and the addition of the new producing assets in the Magdalena Basin.

Financial Summary

	For the three months ended September 30,		For the nine months ended September 30,	
(Financial figures in $'000s except per share amounts)	**2026**	2025	**2026**	2025
Light Crude Oil and Medium Crude Oil (bbl/d)	**24,665**	10,257	**17,676**	10,238
Heavy Crude Oil (bbl/d)	**54,010**	32,026	**40,227**	31,759
Natural gas liquids (boe/d)	**1,871**	268	**969**	319
Average oil production (bbl/d)[1]	**80,546**	42,551	**58,872**	42,316
Average conventional natural gas production (mcf/d)[1]	**16,308**	8,412	**11,856**	6,414
Average oil and natural gas production (boe/d)	**83,264**	43,953	**60,848**	43,385
Production split (% crude oil)	**97**	97	**97**	98
Oil and natural gas sales price, net of purchased oil ($/boe)[6]	**78.17**	62.41	**77.36**	63.68
Operating netback ($/boe)[1]	**37.25**	34.71	**40.15**	36.77
Funds flow provided by operations netback ($/boe)[1]	**26.33**	26.04	**26.65**	27.93
Adjusted funds flow provided by operations netback ($/boe)[1]	**26.33**	26.82	**28.39**	28.22
Oil and natural gas sales	**633,549**	252,424	**1,370,942**	757,129
Funds flow provided by operations[6]	**196,341**	105,298	**442,097**	332,063
Per share – basic[1][3]	**2.04**	1.09	**4.60**	3.41
Per share – diluted [1][3]	**2.04**	1.09	**4.59**	3.41
Adjusted Funds flow provided by operations[6]	**196,341**	108,491	**471,097**	335,449
Per share – basic[1][3]	**2.04**	1.12	**4.90**	3.44
Per share – diluted [1][3]	**2.04**	1.12	**4.89**	3.44
Net income	**75,255**	50,476	**524,140**	180,218
Per share – basic[3]	**0.78**	0.52	**5.45**	1.85
Per share – diluted[3]	**0.78**	0.52	**5.44**	1.85
Dividends paid	**26,772**	26,892	**80,192**	80,818
Per share - Cdn$[3][5]	**0.385**	0.385	**1.155**	1.155
Share repurchases	**—**	7,606	**—**	18,870
Number of shares repurchased (000s)	**—**	620	**—**	1,775
Capital expenditures[2]	**161,770**	79,961	**386,506**	225,705
Free funds flow[2]	**34,571**	25,337	**55,591**	106,358
EBITDA[2]	**242,588**	113,648	**825,969**	376,680
Adjusted EBITDA[2]	**238,024**	121,132	**562,771**	384,284
Total assets (end of period)	**4,454,012**	2,260,531	**4,454,012**	2,260,531
Net debt[4][6]	**911,364**	13,167	**911,364**	13,167
Weighted average shares outstanding (000s)				
Basic	**96,185**	96,874	**96,119**	97,492
Diluted	**96,440**	96,956	**96,352**	97,501
Outstanding shares (end of period) (000s)	**96,196**	96,564	**96,196**	96,564

(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) Syndicated bank credit facility borrowing base of $240.0 million as at September 30, 2026 and September 30, 2025.
(5) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".
(6) Capital management measure. See "Non-GAAP and Other Financial Measures Advisory".

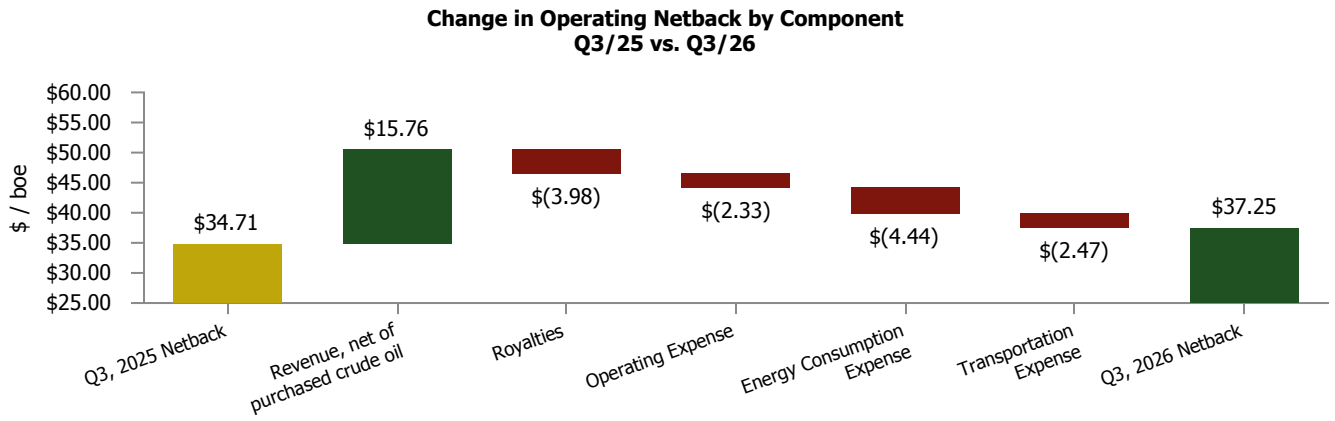
Financial and Operational Results

Consolidated Results of Operations

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

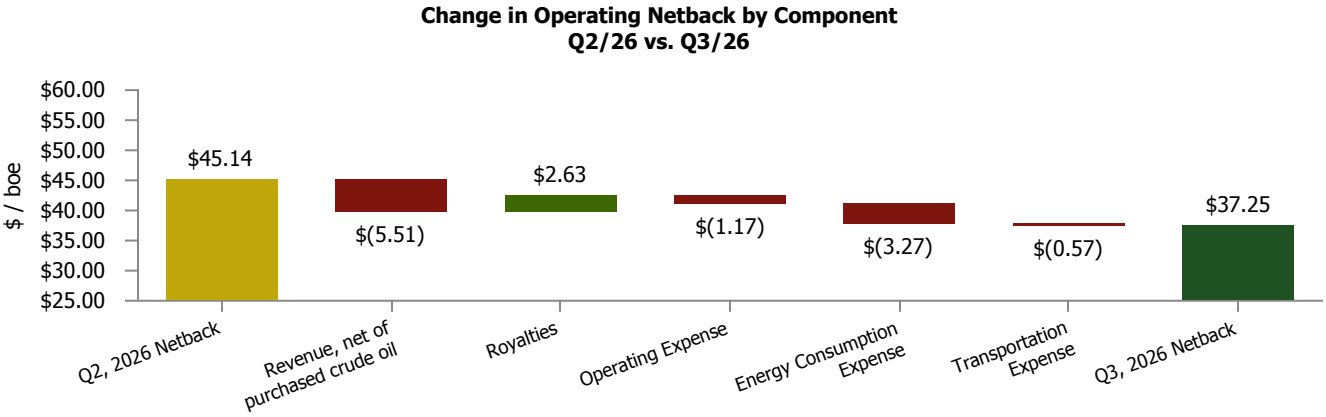
	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	**24,665**	10,257	**17,676**	10,238
Heavy Crude Oil (bbl/d)	**54,010**	32,026	**40,227**	31,759
Natural gas liquids (boe/d)	**1,871**	268	**969**	319
Crude Oil (bbl/d)	**80,546**	42,551	**58,872**	42,316
Conventional Natural Gas (mcf/d)	**16,308**	8,412	**11,856**	6,414
Total (boe/d)	**83,264**	43,953	**60,848**	43,385
Production split (% crude oil production)	**97**	97	**97**	98
Average daily sales of oil and natural gas				
Produced crude oil, before consumption (bbl/d)	**78,329**	42,559	**58,799**	42,476
Produced natural gas (mcf/d)	**16,308**	8,412	**11,856**	6,414
Produced crude oil and natural gas, before consumption (bbl/d)	**81,047**	43,961	**60,775**	43,545
Consumption for fuel	**(3,987)**	—	**(1,656)**	—
Produced oil and natural gas, after consumption	**77,060**	43,961	**59,119**	43,545
Purchased crude oil (bbl/d)	**6,117**	—	**3,125**	4
Total (boe/d)	**83,177**	43,961	**62,244**	43,549
Operating netback ($000s)				
Oil and natural gas sales	**$ 633,549**	$ 252,424	**$ 1,370,942**	$ 757,129
Purchased crude oil[4]	**(50,712)**	—	**(87,468)**	(162)
Oil and natural gas sales, net of purchased crude oil[2][4]	**582,837**	252,424	**1,283,474**	756,967
Royalties	**(86,452)**	(30,785)	**(196,201)**	(98,103)
Net revenue	**496,385**	221,639	**1,087,273**	658,864
Production expense	**(165,039)**	(62,120)	**(313,121)**	(168,470)
Transportation expense	**(53,667)**	(19,124)	**(107,943)**	(53,363)
Operating netback[1]	**$ 277,679**	$ 140,395	**$ 666,209**	$ 437,031
Operating netback (per boe)				
Brent ($/bbl)	**$ 91.29**	$ 68.17	**$ 88.86**	$ 69.91
Parex price differential	**(6.32)**	(5.76)	**(6.23)**	(6.23)
Oil and natural gas sales[2]	**84.97**	62.41	**82.63**	63.68
Purchased crude oil[2][4]	**(6.80)**	—	**(5.27)**	—
Oil and natural gas sales, net of purchased crude oil[2][4]	**78.17**	62.41	**77.36**	63.68
Royalties[2]	**(11.59)**	(7.61)	**(11.83)**	(8.25)
Net revenue[2]	**66.58**	54.80	**65.53**	55.43
Production expense[2]	**(22.13)**	(15.36)	**(18.87)**	(14.17)
Transportation expense[2]	**(7.20)**	(4.73)	**(6.51)**	(4.49)
Operating netback[3]	**$ 37.25**	$ 34.71	**$ 40.15**	$ 36.77

(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) Purchased crude oil cost includes ~$9.4 million of non-cash inventory fair value adjustment as a result of the purchase price allocation for the nine months ended September 30, 2026, equivalent to $0.56/boe.



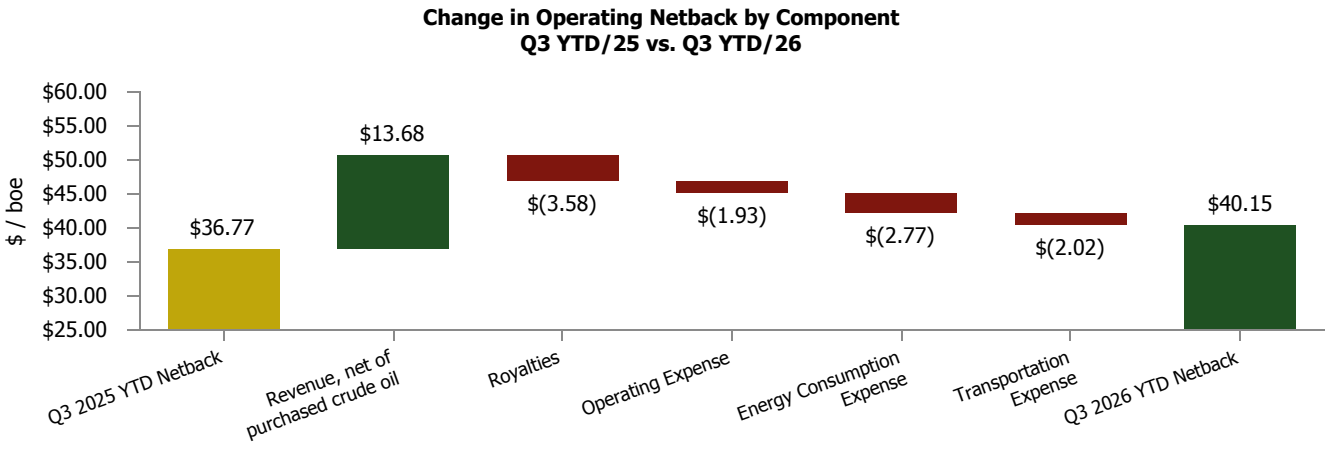
Overall, the operating netback increased by $2.54/boe compared with the third quarter of 2025. The Brent crude oil benchmark price increased by $23.12/bbl, while revenue increased by $15.76/boe. The variance relative to Brent was primarily caused by higher purchased crude oil volumes used for blending associated with the newly acquired heavy oil production.

The benefit of higher revenue was partially offset by higher royalties, operating, energy consumption, and transportation expenses. Royalties increased by $3.98/boe primarily due to higher sales prices. Production expense, which is comprised of operating expense and energy consumption expense, increased by $6.77/boe. Operating expense was higher by $2.33/boe reflecting changes in the production mix and unit production costs including fixed costs and the appreciation of the COP, partially offset by reduced well workovers and facility maintenance costs. Energy consumption expense increased by $4.44/boe, primarily reflecting the higher fuel-powered energy generation costs associated with increased crude oil prices, higher electrical power costs, and the appreciation of the COP. Transportation expense increased by $2.47/boe due to an increase in oil volumes transported by truck and higher gas transportation volumes.



Overall, the operating netback decreased by $7.89/boe compared to the second quarter of 2026. The Brent crude oil price decreased by $5.39/bbl, while revenue decreased by $5.51/boe.

Royalties decreased by $2.63/boe primarily due to lower sales prices. Production expense, which is comprised of operating expense and energy consumption expense, increased by $4.44/boe. Operating expense increased by $1.17/boe reflecting changes in the production mix and unit production costs including fixed costs and the appreciation of the COP, partially offset by reduced well workovers and facility maintenance costs. Energy consumption expense increased by $3.27/boe, primarily reflecting higher electrical power costs and the appreciation of the COP. Transportation expense increased by $0.57/boe due to an increase in oil volumes transported by truck and higher gas transportation volumes.



Overall, the operating netback increased by $3.38/boe compared to the nine month period ended September 30, 2025. The Brent crude oil price increased by $18.95/bbl, while revenue increased by $13.68/boe. The variance relative to Brent was primarily attributable to increased purchased oil for blending associated with newly acquired heavy oil volumes.

The benefit of higher revenue was partially offset by higher royalties, operating, energy consumption, and transportation costs. Royalties increased by $3.58/boe primarily due to higher sales prices. Production expense, which is comprised of operating expense and energy consumption expense, increased by $4.70/boe. Operating expense increased by $1.93/boe, reflecting changes in the production mix and unit production costs including fixed costs and the appreciation of the COP, partially offset by reduced well workovers and facility maintenance costs. Energy consumption expense increased by $2.77/boe, primarily reflecting the higher fuel-powered energy generation costs associated with increased crude oil prices, higher electrical power costs, and the appreciation of the COP. Transportation expense increased by $2.02/boe due to an increase in oil volumes transported by truck and higher gas transportation volumes.

Oil and Natural Gas Sales and Other Revenue

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Llanos	**58,288**	20,612	**37,199**	19,484
LLA-34	**18,812**	20,721	**19,073**	21,476
Magdalena	**5,316**	2,620	**3,845**	2,425
Putumayo	**848**	—	**731**	—
Total Crude oil and natural gas production	**83,264**	43,953	**60,848**	43,385
Crude oil inventory (build) draw	**(2,217)**	8	**(73)**	160
Average daily sales of produced oil and natural gas, before consumption	**81,047**	43,961	**60,775**	43,545
Consumption for fuel	**(3,987)**	—	**(1,656)**	—
Average daily sales of produced oil and natural gas, after consumption	**77,060**	43,961	**59,119**	43,545
Purchased oil	**6,117**	—	**3,125**	4
Sales Volumes	**83,177**	43,961	**62,244**	43,549

On June 1, 2026, the Company successfully closed its previously announced acquisition of Frontera Energy Corporation's Colombian exploration and production assets. The Company's production profile has experienced a step-change following the recently completed transactions, with additional growth opportunities expected as the expanded portfolio is further integrated and developed.

For the period of October 1, 2026, to October 31, 2026, estimated average production was 85,800 boe/d(1), demonstrating positive operational momentum.

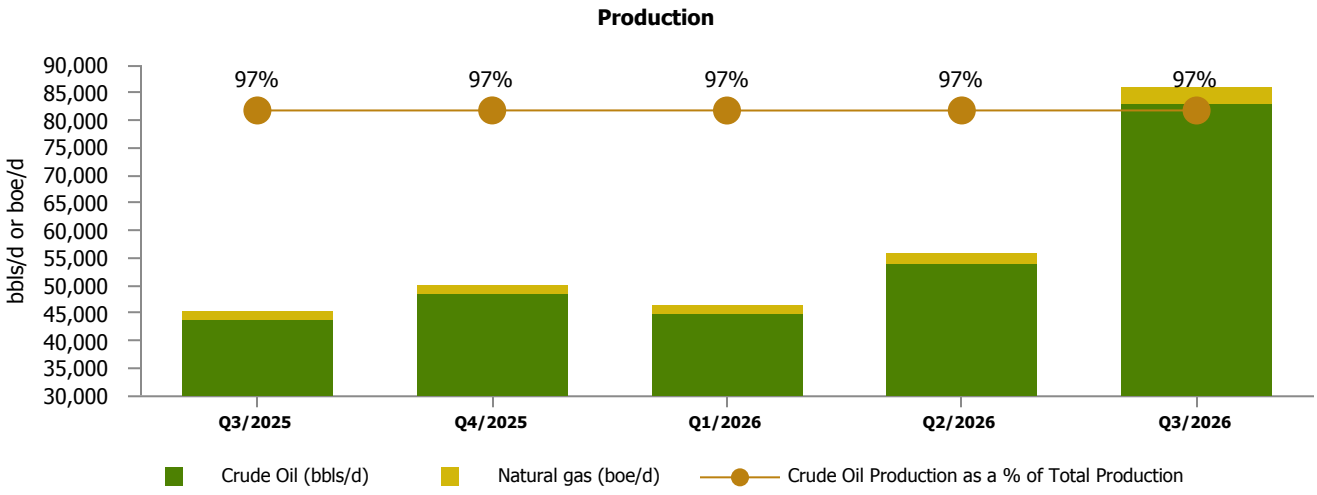
Crude oil and natural gas production for the third quarter of 2026 averaged 83,264 boe/d reflecting the first full quarter of production following the Frontera Transaction and new production from exploration success on Block LLA-111. This is an increase of approximately 89% from the third quarter of 2025 production of 43,953 boe/d and an increase of approximately 54% compared to the second quarter of 2026 production of 54,121 boe/d. Refer to "Summary of Quarterly Results" for production split by product type.

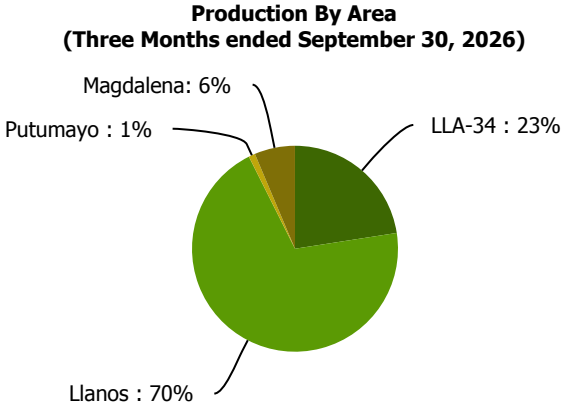
The increase in oil and natural gas production in the third quarter of 2026 compared to the third quarter of 2025 is mainly the result of production added from the closing of the Frontera Transaction, newly added production in the Eastern Llanos Basin, initial Putumayo production, and an increase in gas production 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 weather-related downtime.

The increase in crude oil and natural gas production in the third quarter of 2026 compared to the second quarter of 2026 was mainly attributed to production added from the closing of the Frontera Transaction on June 1, 2026 and newly added production in the Eastern Llanos Basin.

Oil and natural gas sales in the third quarter of 2026 were 83,177 boe/d compared to 43,961 boe/d for the third quarter of 2025, with the step change primarily driven by the closing of the Frontera Transaction, new production in the Eastern Llanos Basin, initial Putumayo production and an increase in gas production in the Magdalena Basin. This was partially offset by a build in produced and purchased crude inventory due to the timing of cargos.

(1) Estimated average production; light & medium crude oil: ~25,416 bbl/d, heavy crude oil: ~55,655 bbl/d, conventional natural gas: ~16,805 mcf/d, natural gas liquids: 1,928 boe/d; rounded for presentation purposes.


Production
90,000
85,000
80,000
75,000
70,000
65,000
60,000
55,000
50,000
45,000
40,000
35,000
30,000
bbls/d or boe/d
97%
97%
97%
97%
97%
Q3/2025
Q4/2025
Q1/2026
Q2/2026
Q3/2026
Crude Oil (bbls/d)
Natural gas (boe/d)
Crude Oil Production as a % of Total Production


Production By Area
(Three Months ended September 30, 2026)
Magdalena: 6%
Putumayo : 1%
LLA-34 : 23%
Llanos : 70%

b) Crude Oil Reference and Realized Prices

Average price for the period	**Q3 2026**	Q2 2026	Q1 2026	Q4 2025	Q3 2025
Brent ($/bbl)	**91.29**	96.68	78.38	63.08	68.17
Parex location, quality and timing differential ($/bbl)	**(3.04)**	(2.88)	(5.52)	(3.03)	(1.94)
Parex wellhead sales discount ($/bbl)	**(2.76)**	(2.32)	(5.16)	(3.35)	(3.91)
Purchased oil ($/bbl)[2]	**(7.04)**	(7.38)	—	—	—
Parex realized oil sales price, net of purchased crude oil ($/bbl)[2]	**78.45**	84.10	67.70	56.70	62.32
Parex realized price (differential), net of purchased crude oil to Brent ($/bbl)	**(12.84)**	(12.58)	(10.68)	(6.38)	(5.85)
Parex transportation expense ($/bbl)[1][2]	**(7.43)**	(6.40)	(5.10)	(5.47)	(4.88)
Parex price differential, net of purchased crude oil and transportation expense ($/bbl)[2]	**(20.27)**	(18.98)	(15.78)	(11.85)	(10.73)

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

During the third quarter of 2026, benchmark Brent oil reference price decreased by $5.39/bbl compared to the second quarter of 2026. Crude oil prices remained volatile during the quarter as market participants continued to assess geopolitical developments in the Middle East and their impact on global crude oil supply and transportation.

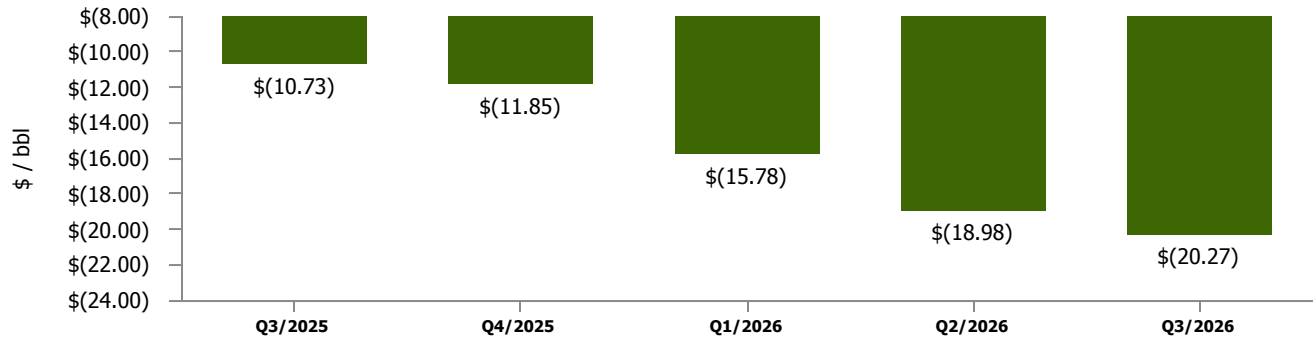
During the third quarter of 2026 the differential between Brent reference pricing and the Company's realized oil sales price, net of purchased crude oil, was $12.84/bbl compared to $12.58/bbl in the second quarter of 2026. The $0.26/bbl increase in the differential was primarily due to increased wellhead sales discounts and location, quality and timing differentials, partially offset by decreased purchased oil cost per bbl associated with the decrease in Brent prices. Compared to the third quarter of 2025 Parex's realized oil price differential, net of purchase oil, increased from $5.85/bbl to $12.84/bbl. The increase was primarily attributable to purchased crude oil used for blending associated with newly acquired production volumes and increased location, quality and timing differentials, partially offset by reduced wellhead sales in favour of higher-priced direct export sales.

The location and quality differential between Brent crude pricing 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. Additional difference between Parex's realized price and Brent crude price are primarily related to wellhead sale marketing contracts, and the timing of oil sales compared to quarterly averages.

The third quarter 2026 location and quality differential of $3.04/bbl increased compared to the third quarter of 2025 of $1.94/bbl. These differentials continue to reflect current global commodity market dynamics, including heavy oil supply and demand fundamentals as well as overall market conditions.

The Vasconia differential to Brent can fluctuate with oil market conditions and for the month of October 2026 was approximately $13/bbl.

Parex Realized Price Differential, Net of Purchased Crude Oil & Transportation Expense



c) Natural Gas Sales and Realized Prices

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Natural gas sales ($000's)	**$ 17,479**	$ 8,421	**$ 37,342**	$ 20,784
Realized sales price ($/Mcf)[(1)]	**11.65**	10.88	**11.54**	11.87

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

Parex's natural gas sales were $17.5 million and $37.3 million for the three and nine months ended September 30, 2026 compared to $8.4 million and $20.8 million in the comparative periods of 2025. The increase in natural gas sales from the comparative periods of 2025 is primarily related to increased volumes sold from the Llanos and Magdalena basins and the closing of the Frontera Transaction on June 1, 2026.

d) Oil and Natural Gas Sales

Third quarter 2026 oil and natural gas sales increased by $381.1 million or 151% as reconciled in the table below to the third quarter of 2025:

($000s)	
Oil and natural gas sales, three months ended September 30, 2025	**$ 252,424**
Sales volume of produced oil, an increase of 75% (31,783 bopd)	**182,226**
Sales volume of purchased oil, an increase of 100% (6,117 bopd)	**35,071**
Oil sales price increase	**154,770**
Sales volume and price change of produced natural gas	**9,058**
Oil and natural gas sales, three months ended September 30, 2026	**$ 633,549**

Oil and natural gas sales increased in the three months ended September 30, 2026 compared to the same period in 2025 mainly due to the increase in world oil prices in addition to higher sales volumes as a result of production added from the closing of the Frontera Transaction on June 1, 2026 and newly added production in the Llanos and Putumayo basins.

e) Crude Oil Inventory

As at September 30, ($000s)	**2026**	2025
Crude oil inventory	**$ 51,176**	$ 182

Crude oil inventory consists of produced and purchased crude injected into pipelines and stored in tanks at the balance sheet date and is recorded at the lower of cost using the weighted average cost method and net realizable value. Costs include the cost of purchased crude oil and direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) incurred in bringing the crude oil to its existing condition and location. At September 30, 2026, the Company had 805.6 mbbls of crude oil inventory recorded at $63.53/bbl compared to 4.9 mbbls at September 30, 2025 recorded at $37.14/bbl. The Q3 2026 build in crude oil inventories of 316,900 bbls was sold post-Q3.

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

For the periods ended (mbbls)	**Sep. 30, 2026**	Jun. 30, 2026	Mar. 31, 2026	Dec. 31, 2025
Crude oil inventory - beginning of the period	**488.7**	132.5	116.9	4.9
Crude oil inventory - acquired on acquisition	**—**	706.3	—	—
Oil production	**7,660.3**	4,769.3	3,892.4	4,333.4
Oil sales	**(7,769.0)**	(5,265.0)	(3,876.8)	(4,221.4)
Consumption for fuel	**(366.8)**	(85.3)	—	—
Purchased oil	**792.4**	230.9	—	—
Crude oil inventory - end of the period	**805.6**	488.7	132.5	116.9
% of period production	**10.5**	10.2	3.4	2.7

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.

f) Purchased Oil

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Purchased oil expense ($000s)	**$ 50,712**	$ —	**$ 87,468**	$ 162

Purchased oil expense has increased for the three and nine months ended September 30, 2026 compared to the same periods in 2025 primarily due to higher oil blending activity associated with the acquired assets.

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 September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Other revenue	**$ 1,971**	$ 2,168	**$ 6,635**	$ 6,999

Royalties

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Base royalties[(1)]	**$ 63,762**	$ 20,282	**$ 128,246**	$ 60,911
Economic rights[(2)]	**22,690**	10,503	**67,955**	37,192
Royalties ($000s)	**$ 86,452**	$ 30,785	**$ 196,201**	$ 98,103
Per unit ($/boe)[(3)]	**11.59**	7.61	**11.83**	8.25
Percentage of sales[(3)]	**15**	12	**15**	13

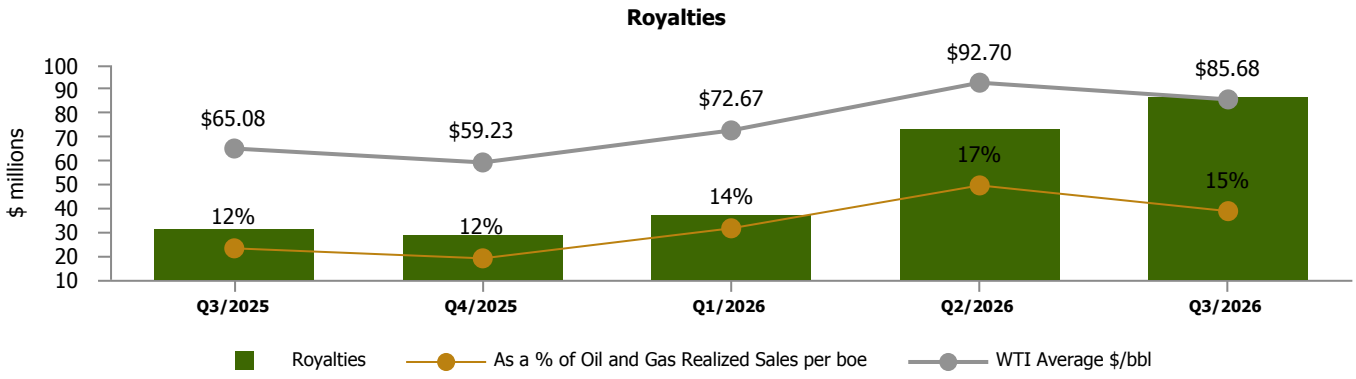
(1) Base royalties are sliding scale royalties based on field production and payable to the Colombian National Hydrocarbon Agency ("ANH"). Refer to the Company's AIF, which may be accessed through the SEDAR+ website at www.sedarplus.ca.
(2) Economic rights include high price share royalties applicable 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 $86.5 million and $196.2 million for the three and nine months ended September 30, 2026, compared to $30.8 million and $98.1 million for the 2025 comparative periods. Royalties as a percentage of sales were 15% for the three and nine months ended September 30, 2026 compared to 12% and 13%, respectively, in 2025.

The increase primarily reflected the increase in world oil prices and base production, partially offset by lower production in areas where high price share royalties are applicable.

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 and nine months ended September 30, 2026 were $85.68 and $83.76 compared to $65.08 and $66.82 for the 2025 comparative period and $92.70 in the second quarter of 2026.

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 September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Operating expense ($000s)	**$ 94,842**	$ 42,005	**$ 191,966**	$ 114,613
Energy consumption expense ($000s)	**70,197**	20,115	**121,155**	53,857
Production expense ($000s)	**$ 165,039**	$ 62,120	**$ 313,121**	$ 168,470
Per unit ($/boe)[1]	**22.13**	15.36	**18.87**	14.17

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

Production expense for the three and nine months ended September 30, 2026 was $22.13/boe and $18.87/boe compared to $15.36/boe and $14.17/boe for the same period in 2025. Production expense increased primarily due to changes in the production mix and unit operating costs including higher fixed costs, increased energy consumption costs, and the appreciation of the COP, partially offset by reduced well workovers and facility maintenance costs.

Production expense for the second quarter of 2026 was $17.69/boe.

Operating expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Operating expense ($000s)	**$ 94,842**	$ 42,005	**$ 191,966**	$ 114,613
Per unit ($/boe)[1]	**12.72**	10.39	**11.57**	9.64

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

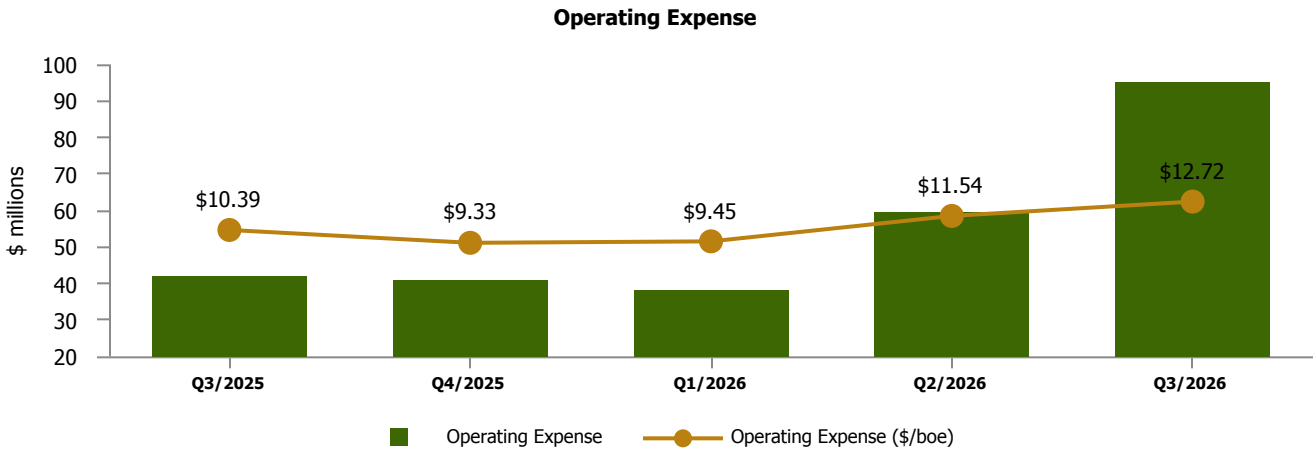
Operating expense for the three and nine months ended September 30, 2026 was $12.72/boe and $11.57/boe compared to $10.39/boe and $9.64/boe for the same periods in 2025. Operating expense for the second quarter of 2026 was $11.54/boe.

The table below provides a reconciliation of the variance in operating expense per boe by its main components:

	Q3 2026 vs Q2 2026	**Q3 2026 vs Q3 2025**	**YTD 2026 vs YTD 2025**
Comparative period operating expense per boe[1]	**$ 11.54**	**$ 10.39**	**$ 9.64**
Well workovers and facility maintenance	**(1.89)**	**(2.74)**	**(1.73)**
Colombian pesos ("COP") appreciation	**1.33**	**2.32**	**1.59**
Non-recurring non-operated production cost adjustment	**—**	**(0.89)**	**(0.30)**
Fixed costs	**2.34**	**3.90**	**2.32**
Other variable costs	**(0.60)**	**(0.26)**	**0.05**
Current period operating expense per boe[1]	**$ 12.72**	**$ 12.72**	**$ 11.57**

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

Operating expense per boe increased for the three and nine months ended September 30, 2026 compared with the same periods in 2025 and the second quarter of 2026. The increase primarily reflected changes in production mix, including production from higher-cost fields to capitalize on higher commodity prices, higher fixed-costs and the appreciation of the COP, partially offset by lower well workover and facility maintenance costs.



Energy Consumption Expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Energy consumption expense ($000s)	**$ 70,197**	$ 20,115	**$ 121,155**	$ 53,857
Per unit ($/boe)[1]	**9.41**	4.97	**7.30**	4.53

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

Energy consumption expense for the three and nine months ended September 30, 2026 was $9.41/boe and $7.30/boe compared to $4.97/boe and $4.53/boe for the same periods in 2025. Energy consumption expense for the second quarter of 2026 was $6.15/boe.

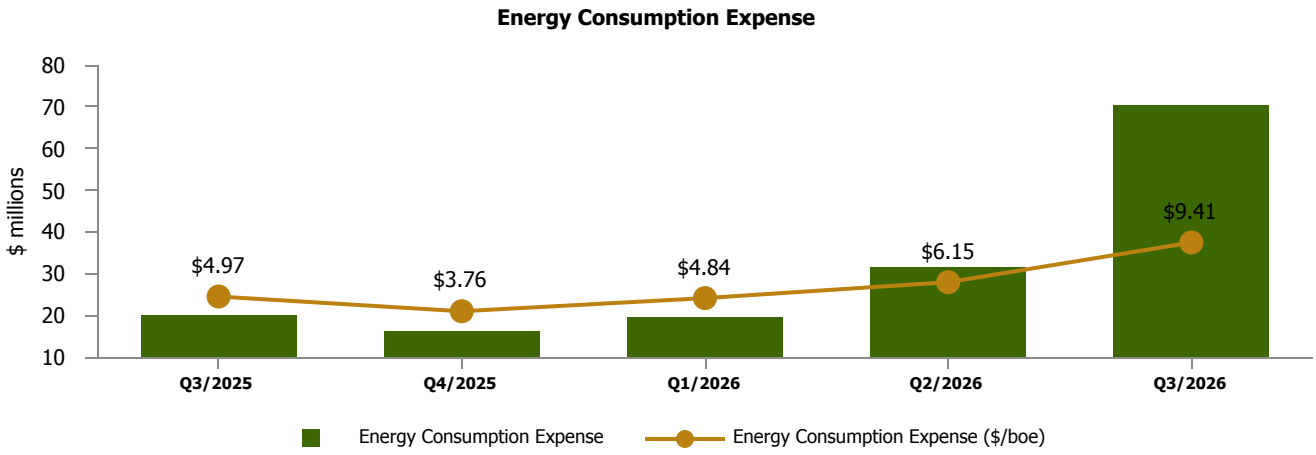
The table below provides a reconciliation of the variance in energy consumption expense per boe by its main components:

	Q3 2026 vs Q2 2026	**Q3 2026 vs Q3 2025**	**YTD 2026 vs YTD 2025**
Comparative period energy consumption expense per boe[1]	**$ 6.15**	**$ 4.97**	**$ 4.53**
Colombian pesos ("COP") appreciation	**0.93**	**1.62**	**0.95**
Change in quantity of energy consumption	**0.47**	**1.07**	**0.47**
Change in price of energy consumption	**1.86**	**1.75**	**1.35**
Current period energy consumption expense per boe[1]	**$ 9.41**	**$ 9.41**	**$ 7.30**

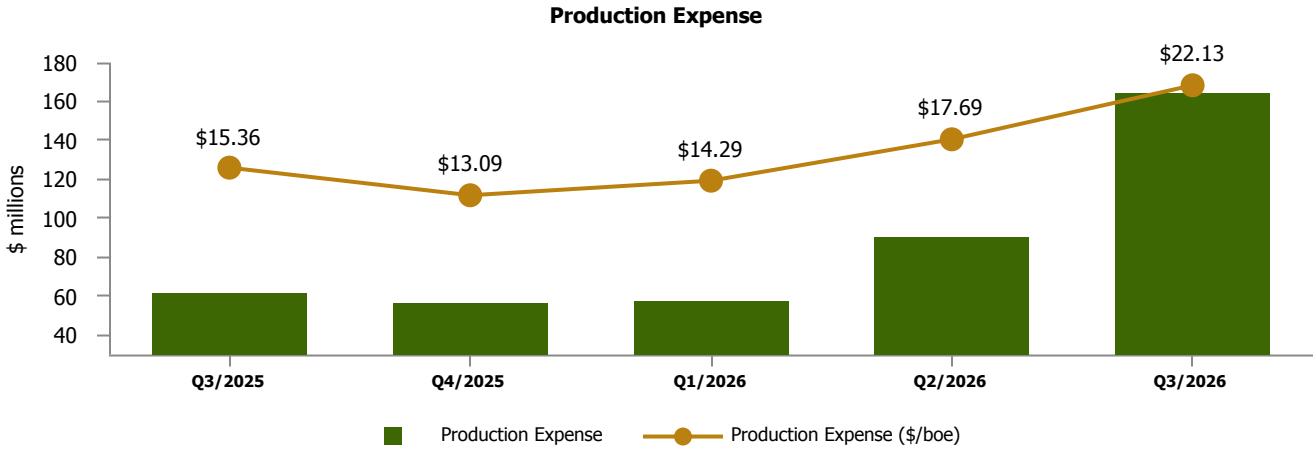
(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Energy consumption expense per boe increased for the three and nine months ended September 30, 2026 compared with the same periods in 2025 and the second quarter of 2026. The increase primarily reflected higher energy consumption volumes, higher electricity prices, higher fuel-powered field operating costs due to higher crude oil prices and the appreciation of the COP. Energy consumption expense is comprised of approximately 40% fuel-related consumption and 60% electricity consumption.

Field operations in Colombia are powered by both electricity and fuel. 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. Elevated energy costs, influenced in part by El Niño-related weather impacts and broader market conditions, are contributing to higher operating cost expectations. Fuel power costs have increased consistent with the increase experienced in world oil prices.



Assuming current conditions persist, the Company expects combined operating expense and energy consumption expense to trend toward the upper end of the guidance range of $22-23/boe for H2 2026.



Transportation Expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Transportation expense ($000s)	**$ 53,667**	$ 19,124	**$ 107,943**	$ 53,363
Per unit ($/boe)[(1)]	**7.20**	4.73	**6.51**	4.49

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

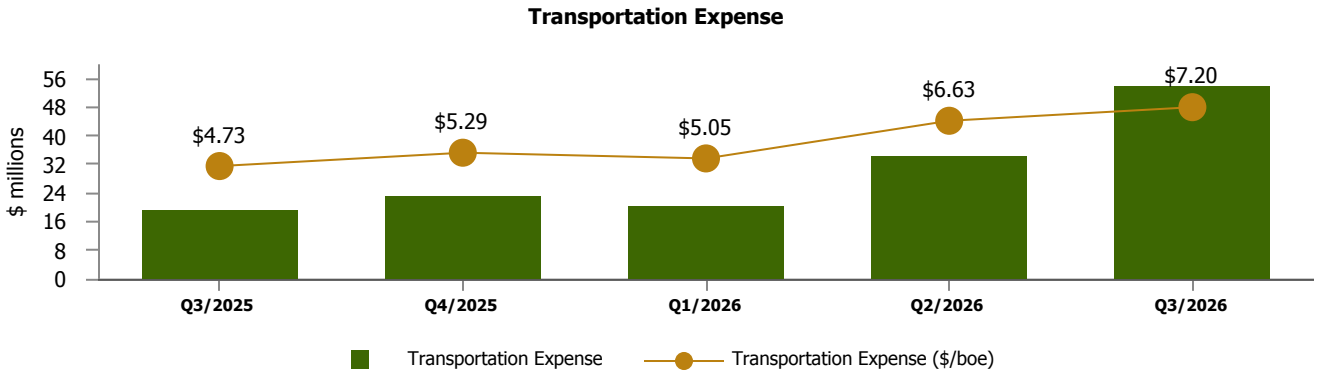
Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility and pipeline tariffs.

For the three and nine months ended September 30, 2026 the cost of transportation on a per boe basis was $7.20/boe and $6.51/boe compared to $4.73/boe and $4.49/boe for the same periods in 2025. The increase reflects changes in the production mix and unit transportation costs of the combined business following the closing of the Frontera Transaction on June 1, 2026.

Transportation expense increased due to an increase in oil volumes transported by truck, higher gas volumes, and the appreciation of the COP. The higher trucked oil volumes are associated with production added due to the Transaction and new production in the Llanos basin. Transportation expense will fluctuate period over period due to the mix of sales contract types in force during the period.

The Company expects transportation expense guidance to be approximately $7.50/boe for H2 2026, after accounting for the Frontera Transaction, and the addition of the new producing assets.

The combined transportation expense and price differential from Brent, on a per boe basis, has increased from the third quarter of 2025 and second quarter of 2026. See "Crude Oil Reference and Realized Prices".



General and Administrative Expense ("G&A")

($000s)	For the three months ended September 30, 2026	2025	For the nine months ended September 30, 2026	2025
Gross G&A	**$ 45,178**	$ 22,408	**$ 99,920**	$ 64,132
G&A recoveries	**(3,944)**	(1,182)	**(8,057)**	(3,658)
Capitalized G&A	**(5,444)**	(2,012)	**(10,234)**	(6,805)
Total net G&A	**$ 35,790**	$ 19,214	**$ 81,629**	$ 53,669
Per unit ($/boe) (1)	**4.67**	4.75	**4.91**	4.53

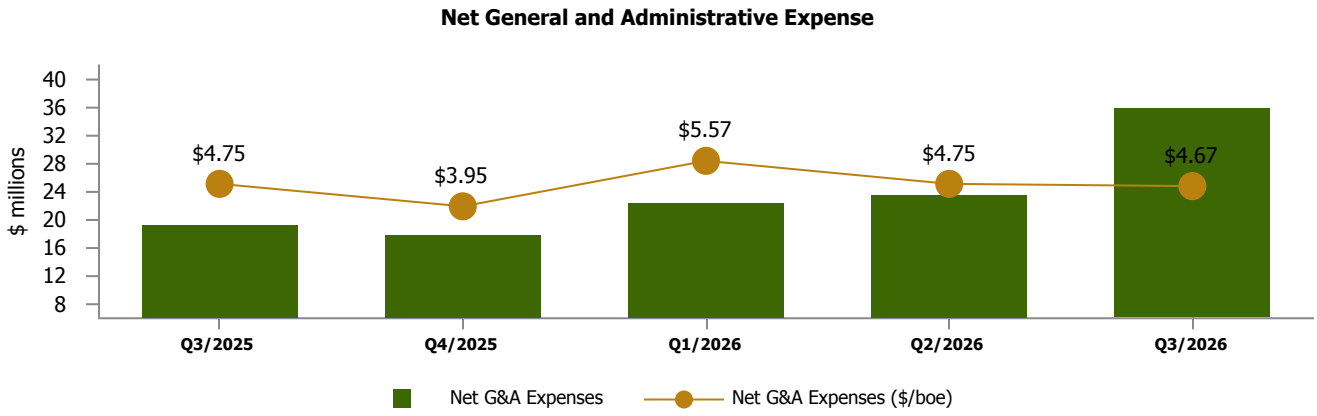
(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures Advisory".

Net G&A was $35.8 million and $81.6 million for the three and nine months ended September 30, 2026 compared to $19.2 million and $53.7 million for the same period in 2025. Gross G&A was $45.2 million and $99.9 million for the three and nine months ended September 30, 2026 (2025 - $22.4 million and $64.1 million). The increase reflects the combined business increased costs and the appreciation of the COP compared to the prior year comparative periods.

On a per boe basis, net G&A for the three and nine months ended September 30, 2026 decreased 2% to $4.67/boe from $4.75/boe and increased 8% to $4.91 from $4.53 in the comparative periods of 2025 reflecting the combined effects of increases in production and costs.

The Company expects G&A expense guidance to be approximately $5.00/boe for H2 2026, after accounting for the Frontera Transaction, and the addition of the new producing assets.

The Company's G&A expense is denominated in local currencies of COP and 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

($000s)	For the three months ended September 30, 2026	2025	For the nine months ended September 30, 2026	2025
Equity settled share-based compensation expense	**$ 273**	$ 169	**$ 712**	$ 531
Cash settled share-based compensation expense	**15,322**	11,733	**33,209**	19,939
Total share-based compensation expense	**$ 15,595**	$ 11,902	**$ 33,921**	$ 20,470

Share-based compensation expense was $15.6 million and $33.9 million for the three and nine months ended September 30, 2026 compared to an expense of $11.9 million and $20.5 million for the comparative periods in 2025.

Equity settled share-based compensation expense was $0.3 million and $0.7 million for the three and nine months ended 2026 compared to $0.2 million and $0.5 million for the three and nine months ended September 30, 2025. 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 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"), cash settled restricted share units ("CRSUs") and deferred share units ("DSUs"). Cash settled share-based compensation expense for the three and nine months ended September 30, 2026 was $15.3 million and $33.2 million compared to $11.7 million and $19.9 million for the same periods in 2025. The increase in expense for the nine months ended September 30, 2026 is mainly attributable to additional units issued and the increase in share price. Parex's share price increased 45% during the nine months ended September 30, 2026.

Obligations for payments of cash under the Company's cash settled incentive plans are accrued as an expense over the vesting period based on the fair value of the units as described in note 17 - Cash Settled Incentive Plans of the interim consolidated financial statements for the nine months ended September 30, 2026. As at September 30, 2026, the total cash settled incentive plans liability accrued was $42.4 million (December 31, 2025 - $37.6 million).

Cash payments to settle cash settled share-based compensation in the three and nine months ended September 30, 2026 were $0.9 million and $30.4 million compared to $1.0 million and $12.3 million for the same periods in 2025. The increase is mainly related to the increase in Parex's share price at the time of settlement and an increase in the number of units settled.

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

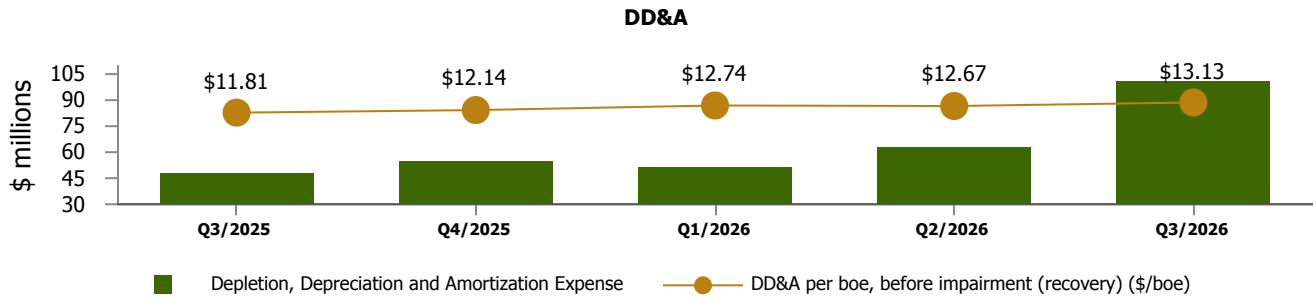
	For the three months ended September 30, 2026	2025	For the nine months ended September 30, 2026	2025
DD&A expense ($000s)	**$ 100,551**	$ 47,767	**$ 214,222**	$ 146,135
Per unit ($/boe)[(1)]	**13.13**	11.81	**12.90**	12.34

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

Third quarter 2026 DD&A was $100.6 million ($13.13/boe) compared to $47.8 million ($11.81/boe) for the same period in 2025.

For the nine months ended September 30, 2026 future development costs of $800.0 million (nine months ended September 30, 2025 - $346.4 million) were included in the depletion calculation.

Third quarter 2026 DD&A of $13.13/boe has increased from the comparative period in 2025 ($11.81/boe) and from the second quarter of 2026 of $12.67/boe due to the increase in depletable base as result of the closing of the Frontera Transaction and transfer of Block LLA-111 costs from E&E.



Foreign Exchange

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Foreign exchange				
Foreign exchange gain - unrealized	**$ (16,483)**	$ (4,926)	**$ (13,652)**	$ (8,082)
Foreign exchange loss - realized	**15,084**	2,217	**15,888**	7,109
Total foreign exchange loss (gain)	**$ (1,399)**	$ (2,709)	**$ 2,236**	$ (973)
Foreign exchange currency risk management contracts				
Foreign currency risk management contracts (gain) loss - unrealized	**$ (334)**	$ 680	**$ (4,441)**	$ (3,452)
Foreign currency risk management contracts gain - realized	**(9,248)**	(3,193)	**(11,025)**	(4,418)
Total foreign currency risk management contracts gain	**$ (9,582)**	$ (2,513)	**$ (15,466)**	$ (7,870)
Net effect of foreign exchange hedging				
Total foreign exchange gain, net of hedging - unrealized	**$ (16,817)**	$ (4,246)	**$ (18,093)**	$ (11,534)
Total foreign exchange loss (gain), net of hedging - realized	**5,836**	(976)	**4,863**	2,691
Total foreign exchange gain, net of hedging	**$ (10,981)**	$ (5,222)	**$ (13,230)**	$ (8,843)
Average foreign exchange rates				
USD$/Cdn$	**1.40**	1.38	**1.38**	1.40
USD$/COP	**3,193**	4,004	**3,500**	4,132

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 operating expense, energy consumption expense, transportation expense, G&A expense, 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 net income and comprehensive income are 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 and nine months ended September 30, 2026, the Company recognized total net foreign exchange gains, including the impact of hedging, of $11.0 million and $13.2 million, respectively, compared with gains of $5.2 million and $8.8 million for the comparative period in 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 net income and 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 with financial institutions in Canada, Switzerland and Colombia.

Foreign Exchange Sensitivity Analysis

		$/boe Impact of change in local currency/$USD exchange rate	
Cost component	Estimated percent of cost denominated in local currency	10% appreciation of local currency	10% depreciation of local currency
Operating expense	90%	$ 1.14	$ (1.14)
Energy consumption expense	85%	$ 0.80	$ (0.80)
Transportation expense	35%	$ 0.25	$ (0.25)
G&A expense	95%	$ 0.44	$ (0.44)

		($000s) Impact of change in local currency/$USD exchange rate	
Cost component	Estimated percent of cost denominated in local currency	10% appreciation of local currency	10% depreciation of local currency
Capital expenditures	25%	$ 4,044	$ (4,044)

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 Q3 2026 per boe costs. The component impact presented in $000s terms uses Q3 2026 capital expenditure costs. This analysis ignores all other factors impacting cost structure including, but not limited to, efficiencies, cost reduction strategies, and cost inflation.

As at September 30, 2026, 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 $22.8 million.

Other Expense

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Other Colombian taxes	**$ 2,208**	$ 2,772	**$ 4,411**	$ 6,098
Colombian tax credit purchased	**—**	—	**—**	8,097
Equity tax	**—**	—	**6,288**	—
Legal provisions	**(1,339)**	—	**180**	—
Loss (gain) on settlement of decommissioning liabilities	**1,325**	(6)	**104**	539
Loss (gain) on disposition of tangible assets	**(1,645)**	46	**2,726**	81
Site restoration costs	**2,013**	—	**12,816**	—
Insurance proceeds	**(2,000)**	—	**(2,000)**	—
Other	**1,215**	1,003	**3,579**	2,600
Total other expense	**$ 1,777**	$ 3,815	**$ 28,104**	$ 17,415

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Non-cash other expense (income)	**$ (1,397)**	$ 40	**$ 3,857**	$ 620
Cash other expense	**3,174**	3,775	**24,247**	16,795
Total other expense	**$ 1,777**	$ 3,815	**$ 28,104**	$ 17,415

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

On February 24, 2026, through Executive Order 0173, the Colombian Government created a new equity tax applicable for fiscal year 2026. The tax applies to legal entities and de facto partnerships that are income tax filers in Colombia. The tax is assessed and becomes payable on equity as of March 1, 2026 equal to or exceeding 200,000 tax unit's value (UVT) (approximately COP$10.5 billion or US$2.7 million) at rates from 0.5% to 1.6%. This Executive Order will be challenged through the Constitutional Court and it may or may not be overturned by the Court. The equity tax payable was settled by June 30, 2026.

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.

A provision has been recognized for the estimated costs required for site restoration in accordance with applicable regulations and contractual obligations. Management expects that a portion of these restoration costs will be recovered through insurance arrangements. Insurance recoveries are recognized only when recovery is virtually certain. For the three and nine months ended September 30, 2026 $2.0 million has been approved by the insurers.

Net Finance Expense

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Bank charges and credit facility fees	**$ 2,546**	$ 1,646	**$ 4,772**	$ 3,837
Interest on bank debt	**2,206**	431	**7,032**	1,665
Interest on senior unsecured notes	**15,427**	—	**23,280**	—
Amortization of deferred financing charges	**1,256**	—	**1,590**	—
Accretion on decommissioning and environmental liabilities	**10,508**	111	**16,776**	6,649
Interest and other income	**(1,781)**	(1,306)	**(7,925)**	(3,215)
Lease obligation interest expense	**724**	48	**1,171**	141
Expected credit loss provision	**501**	3,451	**1,114**	3,302
Other	**3,113**	109	**4,530**	732
Net finance expense	**$ 34,500**	$ 4,490	**$ 52,340**	$ 13,111

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Non-cash finance expense	**$ 12,598**	$ 3,566	**$ 19,480**	$ 9,952
Cash finance expense	**21,902**	924	**32,860**	3,159
Net finance expense	**$ 34,500**	$ 4,490	**$ 52,340**	$ 13,111

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, the amortization of deferred financing charges, the expected credit loss provision and other items.

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 September 30, 2026, the Company had no crude oil risk management contracts in place. The Company is currently unhedged for the remainder of 2026, with full exposure to changes in commodity prices.

The table below summarizes the loss on the commodity risk management contracts that were in place during the three and nine months ended September 30, 2026 and 2025:

	For the three months ended September 30,		For the nine months ended September 30,	
	2026	2025	**2026**	2025
Realized loss (gain) on commodity risk management contracts	**$ —**	$ —	**$ 32,946**	$ (3,337)
Premiums paid on commodity risk management contracts	**—**	3,193	**—**	6,723
Unrealized gain on commodity risk management contracts	**—**	(172)	**(1,281)**	(1,332)
Total loss	**$ —**	$ 3,021	**$ 31,665**	$ 2,054

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 to fund ongoing costs denominated in those currencies.

As at September 30, 2026, the Company had the following foreign currency risk management contracts in place:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP	Max Compensation
September 15, 2026 to December 15, 2026	COP	Collar with limited compensation	$27,000,000	3,700-4,200	800
September 19, 2026 to December 15, 2026	COP	Costless collar	$45,000,000	3,400-3,663	N/A
October 15, 2026 to December 15, 2026	COP	Costless collar	$75,000,000	3,200-3,475	N/A
January 6, 2027 to March 17, 2027	COP	Costless collar	$45,000,000	3,350-3,539	N/A
April 7, 2027 to June 23, 2027	COP	Costless collar	$45,000,000	3,350-3,701	N/A
July 7, 2027 to September 30, 2027	COP	Costless collar	$45,000,000	3,350-3,825	N/A
October 1, 2027 to December 31, 2027	COP	Costless collar	$45,000,000	3,350-4,025	N/A

The table below summarizes the gain on the foreign currency risk management contracts that were in place during the three and nine months ended September 30, 2026 and 2025 which is recorded in the financial statement line item "Foreign exchange gain" in the consolidated statements of net income and comprehensive income:

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Realized gain on foreign currency risk management contracts	**$ (9,248)**	$ (3,193)	**$ (11,025)**	$ (4,418)
Unrealized (gain) loss on foreign currency risk management contracts	**(334)**	680	**(4,441)**	(3,452)
Total gain	**$ (9,582)**	$ (2,513)	**$ (15,466)**	$ (7,870)

Marketable Securities

	September 30, 2026	December 31, 2025
Marketable securities	**$ 63,590**	$ 45,090

In 2025, the Company acquired 6,084,986 common shares of GeoPark Ltd (NYSE: GPRK) (the "GeoPark Shares") for aggregate consideration of $40.5 million ($6.65 per share). The fair value of these shares at September 30, 2026 was $63.6 million, resulting in an unrealized gain of $18.5 million, which is recorded in the consolidated statement of net income and 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.

Income Tax

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Current tax expense	**$ 16,607**	$ 11,135	**$ 34,567**	$ 32,267
Deferred tax (recovery) expense	**13,898**	(4,035)	**(27,404)**	(12,466)
Tax expense	**$ 30,505**	$ 7,100	**$ 7,163**	$ 19,801
Effective current tax rate on funds flow provided by operations before tax[(1)]	**8 %**	10 %	**7 %**	9 %

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

Current tax expense for the three months ended September 30, 2026 was $16.6 million compared to $11.1 million in the three months ended September 30, 2025. The increase in current tax expense for the third quarter of 2026 compared to the third quarter of 2025 is the result of decreases in the available losses and increased funds flow.
For the nine months ended September 30, 2026 current tax expense was comparable to the same period in 2025.

Deferred tax for the three and nine months ended September 30, 2026 was an expense of $13.9 million and recovery of $27.4 million compared to a recovery of $4.0 million and $12.5 million for the three and nine months ended September 30, 2025.

The increase in deferred tax expense for the three months ended September 30, 2026 was primarily due to decreased net operating losses and tax pools. The increase in deferred tax recovery for the nine months ended September 30, 2026 was primarily due to higher tax values than book values for PPE and tax loss carry-forwards associated with the Frontera Transaction and the Ecopetrol Strategic Partnership. The appreciation of COP also contributed to the increase in the deferred tax recovery.

2026 Current Tax Guidance

The Company expects the effective current tax rate on funds flow provided by operations before tax guidance to be approximately 7-10% for both the full year 2026 and H2 2026.

Capital Expenditures

For the three months ended September 30,	Colombia		Canada		Total	
($000s)	**2026**	2025	**2026**	2025	**2026**	2025
Acquisition of unproved properties	**$ 2,973**	$ 3,920	**$ —**	$ —	**$ 2,973**	$ 3,920
Geological and geophysical	**1,058**	36	**—**	—	**1,058**	36
Drilling and completion	**132,472**	63,817	**—**	—	**132,472**	63,817
Well equipment and facilities	**20,451**	11,186	**—**	—	**20,451**	11,186
Other	**4,812**	687	**4**	315	**4,816**	1,002
Total capital expenditures[(1)]	**$ 161,766**	$ 79,646	**$ 4**	$ 315	**$ 161,770**	$ 79,961

For the nine months ended September 30,	Colombia		Canada		Total	
($000s)	**2026**	2025	**2026**	2025	**2026**	2025
Acquisition of unproved properties	**$ 7,381**	$ 5,146	**$ —**	$ —	**$ 7,381**	$ 5,146
Geological and geophysical	**1,893**	9,001	**—**	—	**1,893**	9,001
Drilling and completion	**327,364**	185,926	**—**	—	**327,364**	185,926
Well equipment and facilities	**43,105**	24,406	**—**	—	**43,105**	24,406
Other	**6,348**	687	**415**	539	**6,763**	1,226
Total capital expenditures[(1)]	**$ 386,091**	$225,166	**$ 415**	$ 539	**$ 386,506**	$ 225,705

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

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

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Llanos Basin	**$ 103,148**	$ 66,015	**$ 225,335**	$ 178,214
Putumayo Basin	**13,944**	844	**62,083**	3,233
Block LLA-34	**19,996**	$ 9,260	**50,113**	37,603
Magdalena Basin	**19,866**	2,840	**42,212**	5,429
Canada and Colombia - Corporate	**4,816**	1,002	**6,763**	1,226
Total capital expenditures[(1)]	**$ 161,770**	$ 79,961	**$ 386,506**	$ 225,705

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

During the nine months ended September 30, 2026 the Company incurred $386.5 million of capital expenditures with 96% spent on drilling, completion, well equipment and facilities in Colombia. During the nine months ended September 30, 2025, the Company incurred $225.7 million of capital expenditures with 93% spent on drilling, completion, well equipment and facilities in Colombia.

During the third quarter of 2026 the Company incurred $161.8 million of capital expenditures with 95% spent on drilling, completion, well equipment and facilities in Colombia. During the third quarter of 2025, the Company incurred $80.0 million of capital expenditures with 94% spent on drilling, completion, well equipment and facilities in Colombia.

During the nine months ended September 30, 2026 the Company's capital expenditures of $386.5 million were self-funded from funds flow provided by operations of $442.1 million.

Business Combination

Frontera Transaction

On June 1, 2026, the Company closed its previously announced acquisition of all the Colombian exploration and production assets of Frontera Energy Corporation ("Frontera"), pursuant to which the Company, through a wholly-owned subsidiary, acquired 100% of the issued and outstanding shares of Sabana Petroleum International Holdings B.V. (formerly Frontera Petroleum International Holdings B.V.) ("Sabana"), which holds all of Frontera's exploration and production assets in Colombia, for cash consideration of $500 million, plus the assumption of debt, in addition to a contingent payment of $25 million (the "Frontera Transaction"). The Frontera Transaction was funded with the proceeds from the Company's issuance of senior unsecured notes, see Note 14 - Debt of the interim consolidated financial statements for the period ended September 30, 2026.

The contingent consideration is payable to Frontera if, within 12 months following the closing of the Frontera Transaction, the Company obtains a contractual amendment or other binding agreement extending the term of the Quifa Association Contract. At the acquisition date, the contingent consideration was recognized at its estimated fair value of $12.5 million, reflecting management's probability-weighted assessment of the payment condition being satisfied. As any payment, if triggered, is expected within 12 months of the acquisition date, the effect of discounting was not material.

The fair value measurement of the contingent consideration is classified within Level 3 of the fair value hierarchy because it uses significant unobservable inputs, principally the probability of obtaining the required contractual extension. The contingent consideration was remeasured at September 30, 2026, with no change in its fair value recognized during the period.

IFRS 3 requires the amounts to record for the underlying assets and liabilities acquired to be determined at the closing date (the "acquisition date") whereas the consideration for the business was negotiated earlier and voted on by the Frontera shareholders on April 30, 2026. Furthermore, deferred tax assets are recorded at undiscounted amounts based on temporary differences existing at the acquisition date and are therefore not recorded at fair value under IFRS. The tax basis of the underlying assets acquired is in Colombian pesos which differs from the functional currency of the Company and due to volatility in currencies this also significantly increased the US dollar equivalent value of the tax pools at the acquisition date relative to the time when the purchase was negotiated. As a result, the Company has estimated that the deferred tax assets contributed to the recognition of a bargain purchase gain approximating the deferred tax assets recognized.

The consolidated statements of net income and comprehensive income include results of operations of the Frontera Transaction since the closing date of June 1, 2026. The Company incurred transaction costs in connection with the Frontera Transaction of $29.0 million for the nine months ended September 30, 2026, which are expensed as incurred and presented in the consolidated statements of net income and comprehensive income.

The below amounts are estimates which were made by management at the time of the preparation of these condensed interim consolidated financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized for a period of up to one year. The pro forma information disclosed below is presented for informational purposes only and is not necessarily indicative of the results that would have been achieved had the Frontera Transaction occurred on January 1, 2026, nor is it indicative of future results.

The key assumptions used in the business combination to calculate the purchase price allocation include reserve estimates of proved plus probable reserves acquired that are based on production forecasts, future commodity prices, future development costs and future production costs.

During the three months ended September 30, 2026, the Company continued to refine the provisional purchase price allocation for the Frontera Transaction as additional information became available regarding facts and circumstances that existed as of the acquisition date. As a result, the Company recognized an additional provision of $11.0 million as at June 1, 2026, with a corresponding increase to property, plant and equipment and decrease of $4.9 million to the deferred tax asset and corresponding bargain purchase gain. The adjustment reflects information obtained during the measurement period relating to conditions that existed at the acquisition date and has therefore been reflected retrospectively in the provisional acquisition accounting.

As a result of the acquisition, the Company recognized a bargain purchase gain of $297.6 million, representing the excess of the fair value of the identifiable net assets acquired over the consideration transferred. The bargain purchase gain was recognized in the consolidated statements of net income and comprehensive income.

Before recognizing the bargain purchase gain, the Company assessed the completeness and accuracy of the assets acquired, liabilities assumed and consideration transferred, including the valuation methodologies and key assumptions applied in determining acquisition-date fair values, in accordance with IFRS 3.

The following table summarizes the recognizable assets acquired, liabilities assumed and consideration paid pursuant to the Frontera Transaction:

Assets acquired and liabilities assumed		
Assets		
Cash and cash equivalents	$	165,859
Restricted cash and cash equivalents		10,657
Accounts receivables		84,094
Prepaids and other current assets		11,181
Short-term inventory		67,569
Current income tax receivable		61,927
Exploration and evaluation assets		11,089
Property, plant and equipment		997,507
Right-of-use-asset		16,003
Other long-term assets		18,198
Deferred tax asset		297,610
Liabilities		
Accounts payable and accrued liabilities		(354,981)
Derivative financial instruments		(1,282)
Long-term debt - unsecured notes		(307,311)
Customer prepayments		(80,300)
Lease obligations		(16,003)
Decommissioning and environmental liabilities		(179,999)
Other long-term liabilities		(8,013)
Net assets acquired	**$**	**793,805**
Consideration transferred		(496,195)
Bargain purchase gain	**$**	**297,610**

Consideration for the acquisition		
Base purchase price	$	500,000
Purchase price adjustments		(16,305)
Cash consideration paid at closing		483,695
Fair value of contingent consideration		12,500
Total consideration	**$**	**496,195**
Cash paid	$	483,695
Less: Cash and cash equivalents acquired		(176,516)
Net cash outflow on acquisition	**$**	**307,179**

The pro forma results for the nine month period ended September 30, 2026 are shown below, as if the Frontera Transaction had occurred on January 1, 2026. Pro forma results are not indicative of actual results or future performance.

Oil and natural gas sales	$	1,839,106
Net revenue less direct costs[(1)]	$	847,210

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

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 net income and comprehensive income for the nine months ended September 30, 2026 includes $437.9 million of oil and natural gas sales attributable to the assets acquired since the Frontera Transaction. Revenue less direct costs for the nine months ended September 30, 2026 attributable to the assets acquired since the Frontera Transaction is $138.6 million.

Ecopetrol Strategic Partnership

On July 29, 2026, the Company closed the previously announced executed agreement with its strategic partner Ecopetrol S.A. ("Ecopetrol"), following receipt of the required regulatory approvals. Under the agreement, the Company will earn a 50% participating share in the Casabe and Llanito blocks in the Magdalena Basin of Colombia, upon spudding the first well on each block in exchange for a commitment of a gross capital expenditure program of $250 million over five years, of which $125 million represents the commitment to fund Ecopetrol's share.

The transaction was accounted for as a business combination under IFRS 3 as the initial participating interest acquired by the Company included interests in existing proved developed producing reserves and current production, together with the related operating activities and obligations, which collectively constituted a business. The acquisition-date consideration was determined based on the present value of the Company's future investment commitment attributable to the participating interest acquired at the acquisition date.

The initial acquisition reflects the minimum participating interest in the existing producing properties to which the Company is entitled under the arrangement. The Company's remaining incremental participating interest will be earned through future investment activities under the agreement and is not included in the initial purchase price allocation.

The below amounts are estimates which were made by management at the time of the preparation of these condensed interim consolidated financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized for a period of up to one year.

The key assumptions used in the business combination to calculate the purchase price allocation include reserve estimates of proved developed producing reserves acquired that are based on production forecasts, future commodity prices, future development costs and future production costs and assumptions associated with the Company's carry commitment.

The following table summarizes the recognizable assets acquired, liabilities assumed and consideration pursuant to the agreement:

Assets acquired and liabilities assumed		
Assets		
Property, plant and equipment	**$**	**56,447**
Liabilities		
Decommissioning and environmental liabilities		**(1,275)**
Net assets acquired	**$**	**55,172**
Deferred consideration		
Current obligation	**$**	**14,344**
Long-term obligation		**40,828**
Total deferred consideration	**$**	**55,172**

The deferred consideration represents the present value of the portion of the Company's future investment commitment attributable to the initial participating interest acquired. The liability will be accreted over the expected investment period, with the accretion recognized as a finance expense. As expenditures are incurred under the investment commitment, the corresponding portion of the deferred consideration liability will be settled.

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 net income and 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 nine month period ended September 30, 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	$	760,892
Net revenue less direct costs or operating netback[(1)]	$	440,210

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

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 net income and comprehensive income for the nine months ended September 30, 2025 includes $18.8 million of oil sales attributable to the assets acquired since the LLA-32 Acquisition. Revenue less direct costs for the nine months ended September 30, 2025 attributable to the assets acquired since the LLA-32 Acquisition is $12.6 million.

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.

Cost		
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**
Additions		10,698
Transfers to E&E and PP&E assets		(17,636)
Sale of inventory		(2,413)
Balance at September 30, 2026	**$**	**166,075**

The table below represents the other long-term inventory expenditures for the three and nine months ended September 30, 2026 and 2025:

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Additions	**$ 3,474**	$ 3,701	**$ 10,698**	$ 9,578
Transfers to D&P and E&E assets	**(3,078)**	(5,272)	**(17,636)**	(16,782)
Transfer to production costs	**—**	(14)	**—**	(1,998)
Sale of inventory	**(1,687)**	—	**(2,413)**	(698)
Total long-term inventory expenditures, net of transfers and sales	**$ (1,291)**	$ (1,585)	**$ (9,351)**	$ (9,900)

Summary of Quarterly Results

Three months ended ($000s) (except per share amounts)	**Sep. 30, 2026**	Jun. 30, 2026	Mar. 31, 2026	Dec. 31, 2025
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	**24,665**	14,515	13,726	14,664
Heavy Crude Oil (bbl/d)	**54,010**	37,130	29,269	32,267
Natural gas liquids (boe/d)	**1,871**	765	254	171
Crude Oil (bbl/d)	**80,546**	52,410	43,249	47,102
Conventional Natural Gas (mcf/d)	**16,308**	10,266	8,916	9,024
Total (boe/d)	**83,264**	54,121	44,735	48,606
Oil and natural gas sales price, net of purchased oil ($/boe)[6]	**78.17**	83.68	67.67	57.05
Financial ($000s except per share amounts)				
Oil and natural gas sales	**$ 633,549**	$ 466,016	$ 271,377	$ 248,713
Funds flow provided by operations[5]	**$ 196,341**	$ 132,054	$ 113,702	$ 122,922
Per share – basic[2][4]	**2.04**	1.37	1.18	1.28
Per share – diluted[2][4]	**2.04**	1.37	1.18	1.28
Adjusted Funds flow provided by operations[5]	**$ 196,341**	$ 191,155	$ 116,548	$ 122,115
Per share – basic[2][4]	**2.04**	1.99	1.21	1.27
Per share – diluted[2][4]	**2.04**	1.98	1.21	1.27
Net income	**$ 75,255**	$ 444,296	$ 4,589	$ 74,865
Per share – basic[4]	**0.78**	4.62	0.05	0.78
Per share – diluted[4]	**0.78**	4.61	0.05	0.78
Dividends paid	**$ 26,772**	$ 26,483	$ 26,937	$ 26,853
Per share - Cdn$[4][6]	**0.385**	0.385	0.385	0.385
Capital Expenditures[1]	**$ 161,770**	$ 133,693	$ 91,043	$ 84,620
Total assets (end of period)	**$ 4,454,012**	$ 4,235,530	$ 2,496,102	$ 2,341,092
Outstanding shares (end of period) (000s)	**96,196**	96,180	96,115	95,974
Net debt[5]	**$ 911,364**	$ 906,598	$ 39,694	$ 4,973
Working capital (deficit) surplus (end of period)[3][5]	**$ (35,976)**	$ (83,222)	$ 135,506	$ 28,027

Three months ended ($000s) (except per share amounts)	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024
Average daily production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,257	10,182	10,276	9,290
Heavy Crude Oil (bbl/d)	32,026	31,047	32,207	34,882
Natural gas liquids (boe/d)	268	316	374	260
Crude Oil (bbl/d)	42,551	41,545	42,857	44,432
Conventional Natural Gas (mcf/d)	8,412	5,982	4,806	5,190
Total (boe/d)	43,953	42,542	43,658	45,297
Oil and natural gas sales price, net of purchased oil ($/boe)[6]	62.41	61.35	67.29	63.73
Financial ($000s except per share amounts)				
Oil and natural gas sales	$ 252,424	$ 239,070	$ 265,635	$ 277,824
Funds flow provided by operations[5]	$ 105,298	$ 104,821	$ 121,944	$ 141,201
Per share – basic[2][4]	1.09	1.08	1.24	1.43
Per share – diluted[2][4]	1.09	1.08	1.24	1.43
Adjusted Funds flow provided by operations[5]	$ 108,491	$ 103,653	$ 123,305	$ 141,201
Per share – basic[2][4]	1.12	1.06	1.26	1.43
Per share – diluted[2][4]	1.12	1.06	1.26	1.43
Net income (loss)	$ 50,476	$ 49,113	$ 80,629	$ (69,051)
Per share – basic[4]	0.52	0.50	0.82	(0.70)
Per share – diluted[4]	0.52	0.50	0.82	(0.70)
Dividends paid	$ 26,892	$ 27,561	$ 26,365	$ 26,658
Per share - Cdn$[4][6]	0.385	0.385	0.385	0.385
Capital Expenditures[1]	$ 79,961	$ 88,690	$ 57,054	$ 82,110
Total assets (end of period)	$ 2,260,531	$ 2,223,178	$ 2,197,955	$ 2,155,062
Outstanding shares (end of period) (000s)	96,564	97,184	97,814	98,339
Net debt (net cash)[5]	13,167	(2,048)	(19,040)	603
Working capital (deficit) surplus (end of period)[3][5]	$ (3,167)	$ 20,048	$ 69,040	$ 59,397

(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). The Frontera Transaction, completed on June 1, 2026, also impacted quarter-over-quarter trends through the inclusion of the acquired operations' production, revenue, operating expenses and other financial statement items.

Net income is also impacted by changes in non-cash impairment of property, plant and equipment, exploration and evaluation and long-term inventory assets, as well as acquisition-related accounting adjustments, including fair value adjustments recognized as part of the purchase price allocation. 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 expenditures and long-term inventory expenditures in accordance with the Company's activities, as well as the timing of settlement of receivables, payables and income taxes. Quarter-over-quarter working capital changes also reflect the impact of the Frontera Transaction, including the assumption of acquired working capital balances, debt-related balances and other liabilities recognized at fair value on the acquisition date. Financing activities, including bank debt borrowings or repayments, the issuance or repayment of debt, and the cost associated with share repurchases and dividend payments, also impact working capital and liquidity trends.

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.

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. The Company primarily 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 to include shareholders' equity, the credit facility, unsecured notes and its working capital. As at September 30, 2026, shareholders' equity was $2,400.5 million (December 31, 2025 - $1,952.9 million).

As at September 30, 2026, the Company had a working capital deficit(1) of $36.0 million as compared to a working capital surplus(1) of $28.0 million at December 31, 2025. The decrease was primarily attributable to the Frontera Transaction and the related assumption of current liabilities, partially offset by higher unrestricted cash balances.

As at September 30, 2026, Parex held $142.7 million of unrestricted cash compared to $58.3 million at December 31, 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 and has a current borrowing base of $240.0 million (December 31, 2025 - $240.0 million). The credit facility is intended to provide additional liquidity and fund cash or letter of credit needs as they arise. As at September 30, 2026, there was $82.5 million drawn on the credit facility (at December 31, 2025 - $33.0 million was drawn). The credit facility is secured by the Company's Colombian assets and has a final maturity date of May 31, 2028. The next annual review is scheduled to occur in May 2027. 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, senior secured debt to adjusted EBITDA test of 3.00:1, and other standard business operating covenants for each reporting period. The Company is in compliance with all covenants.

On May 11, 2026, in conjunction with the Frontera Transaction, the Company completed a $500.0 million private placement offering of senior unsecured notes due 2031 ("2031 Unsecured Notes") to fund the acquisition and for general corporate purposes. The notes were priced at par, bear interest at a rate of 8.50% per annum and mature on May 11, 2031, unless earlier redeemed or repurchased. The interest is payable semi-annually in arrears on November 11 and May 11 of each year, beginning on November 11, 2026. The carrying value for the 2031 Unsecured Notes as at September 30, 2026 was $485.6 million compared to the fair value of $501.3 million (Level 2 input). Gross proceeds from the issuance were $500.0 million, with initial carrying amount of $484.6 million after deducting the initial offering expenses payable by the Company of $15.4 million. Key covenants include a fixed charge test of not less than 2.25:1 and net 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 key covenants at September 30, 2026.

As part of the Frontera Transaction, the Company assumed all of Frontera's obligations under its $310.0 million aggregate principal amount of 7.875% senior unsecured notes due 2028 ("2028 Unsecured Notes") issued on June 21, 2021. The interest is payable semi-annually in arrears on June 21 and December 21 of each year, beginning on December 21, 2021. The 2028 Unsecured Notes will mature June 21, 2028, unless earlier redeemed or repurchased. The carrying value for the 2028 Unsecured Notes as at September 30, 2026 was $307.3 million compared to the fair value of $308.9 million (Level 2 input). Key covenants include a fixed charge test of not less than 2.25:1 and net debt to adjusted EBITDA test of 3.25:1 and other standard business operating covenants for each reporting period. The Company was in compliance with all key covenants at September 30, 2026.

The 2028 and 2031 unsecured notes are subordinated to secured debt to the extent of the value of the assets securing such indebtedness.

Refer to note 27 - Commitments and Contingencies of the interim financial statements for the period ended September 30, 2026 for information regarding performance guarantees and 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 September 30, 2026 the Company had 96,195,900 common shares outstanding compared to 95,974,136 at December 31, 2025. At November 5, 2026 the Company had 96,262,844 common shares outstanding.

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 November 5, 2026 Parex has the following securities outstanding:

	Number	%
Common shares	96,262,844	99 %
Stock options	1,137,703	1 %
	97,400,547	**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 Contingencies

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.

The following table summarizes the Company's estimated undiscounted commitments as at September 30, 2026:

	2026	2027	2028	2029	2030	Thereafter	Total
Minimum work commitments	$ 38,261	$ 141,777	$ 101,524	$ 78,789	$ —	$ 637,974	$ 998,325
Transportation	7,205	2,554	—	—	—	—	9,759
Operating leases	639	2,424	741	—	—	—	3,804
Other commitments							
Purchased oil	24,738	—	—	—	—	—	24,738
Energy supply commitments	11,071	12,890	13,512	9,631	9,920	10,206	67,230
Decommissioning and Environmental Obligations	18,970	—	—	—	—	798,854	817,824
Total	**$ 100,884**	**$ 159,645**	**$ 115,777**	**$ 88,420**	**$ 9,920**	**$1,447,034**	**$1,921,680**

Minimum work commitments

The value of the Company's commitments as at September 30, 2026 in respect of the Colombia work commitments under E&P contracts, joint venture farm-in arrangements and business collaboration agreements are as disclosed above. At September 30, 2026, performance guarantees to support the work commitments on the Company's Colombian concessions were in place with the ANH and Ecopetrol joint venture blocks in the amount of $505.0 million (December 31, 2025 - $235.1 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.

The value of the Company's exploration commitments as at September 30, 2026 in respect of the Colombia work commitments under E&P contracts, and joint venture farm-in arrangements, is as disclosed above.

Transportation

Includes ship-or-pay contracts with Bicentenario and Cenit where the pledged inventory crude oil is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. A pledge agreement with Ocensa and Cenit is in place, which guarantees the payment obligations of both contracts.

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 September 30, 2026 are as disclosed above.

Purchased oil

Includes an agreement in place covering crude oil purchases for 2026.

Energy supply

Includes executed contracts for grid-connected, on-site generation, and solar power sources, ensuring the electricity supply across operational blocks, particularly Quifa and CPE-6.

Contingencies

The Company is involved in various legal, regulatory and administrative claims, and proceedings arising from the normal course of business. Given the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. Management has assessed the likelihood of settlement and determined the best estimate based on relevant information and the probability of outcomes. Significant judgement was applied in estimating the range of possible outcomes given the uncertainty involved.

Refer to Note 8 - Business Combinations of the condensed interim financial statements for the period ended September 30, 2026 regarding the contingent payment agreed to as part of the consideration of the Frontera Transaction.

Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2024	$ 68,469	$ 9,206	$ 77,675
Additions	6,407	3,275	9,682
Property acquisitions - Note 9	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
Additions	17,030	2,827	19,857
Acquired on close of business combinations - Note 8	157,524	23,750	181,274
Discount rate adjustment on obligations acquired	32,355	5,894	38,249
Settlements of obligations during the period	(18,866)	(4,802)	(23,668)
Loss on settlement of obligations	104	—	104
Accretion expense	14,935	1,841	16,776
Change in estimate - inflation and discount rates	2,053	1,672	3,725
Change in estimate - costs and timing of settlements	17,567	2,235	19,802
Foreign exchange loss	9,879	4,033	13,912
Balance, September 30, 2026	**$ 310,144**	**$ 49,052**	**$ 359,196**
Current obligation	(11,130)	(7,840)	(18,970)
Long-term obligation	**$ 299,014**	**$ 41,212**	**$ 340,226**

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 September 30, 2026, the estimated costs to abandon and reclaim the wells, well sites and facilities 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 $711.7 million as at September 30, 2026 (December 31, 2025 – $244.5 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.4% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the decommissioning liability is $11.1 million (December 31, 2025 – $7.3 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 $106.1 million as at September 30, 2026 (December 31, 2025 – $29.7 million) with the majority of these costs anticipated to occur in 2033 or later in Colombia. A risk-free discount rate of 12.4% and an inflation rate of 4.0% were used in the valuation of the liabilities (December 31, 2025 – 12.5% risk-free discount rate and a 4.0% inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the environmental liability is $7.8 million (December 31, 2025 – $2.8 million) that is classified as a current obligation.

Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning 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 liabilities to change are:

- Changes in laws and legislation;
- 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 liabilities.

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", "continue", "forecast", "project", "intend", "believe", "anticipate", "estimate", "guidance", "potential", "should", "target", "trend" 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 total shareholder return, while investing in the Company's assets;
- Parex'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 expectations as to debt levels, commodity risk management and its foreign currency risk management activities, including its COP hedging program for Q4 2026 and 2027 and the expected proportion of Colombian peso-denominated costs covered by such arrangements;
- Parex's expectations that a portion of its site restoration costs will be recovered through insurance;
- Parex's H2 and FY 2026 guidance, including its anticipated capital expenditures, funds flow provided by operations and average production;
- Parex's expectations regarding the moderation of crude oil differentials and operating costs under more normalized market conditions;
- Parex's expectation that FY 2026 average production will exceed its previous guidance range;
- Parex's anticipated H2 2026 production, transportation and G&A expenses per boe;
- Parex's expectations that its transportation expense will fluctuate period over period due to the mix of sales contract types in force during the period;
- Parex's expectations regarding the continued development, production performance and growth opportunities of the Company's expanded asset portfolio
- that Parex will review its exposure to foreign currency variations on an ongoing basis;
- Parex's foreign exchange sensitivity analysis;
- the terms and purpose of the Company's credit facility including the timing of the next annual review;
- the Company's plan to draw on the credit facility at various times to manage timing differences associated with the 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 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;
- expectations regarding the integration of the Frontera assets, optimization of the Company's operating model and the identification, timing and realization of anticipated operational, strategic and other synergies, efficiencies and benefits from the Frontera Transaction therefrom;
- expectations regarding the Quifa Association Contract, including the potential extension thereof and the amount and payment of contingent consideration associated with the Frontera Transaction;
- expectations regarding Parex's participation in the Casabe and Llanito blocks in the Magdalena Basin under the Ecopetrol Strategic Partnership, including the timing of well spuds, the earning of participating interests, the execution and timing of the capital program and carry commitments, production and development activities, and the realization of anticipated benefits therefrom;
- the amount, timing and settlement of deferred consideration and future investment commitments associated with the Ecopetrol Strategic Partnership;
- expectations regarding exploration success at LLA-111 and current and anticipated production levels therefrom;
- performance projections in connection with elevated energy costs, including expectations that combined operating expense and energy consumption expense will trend toward the upper end of H2 2026 guidance;

- the Company's risk management strategy and the use of derivatives primarily with financial institutions to manage movements in the price of crude oil, fluctuations in the USD/COP exchange rate and interest rate movements; that the Company will be able to manage and forecast cash flow through derivative contracts;
- the Company's estimated effective current tax rate for H2 2026 and FY 2026;
- Parex's plans of deploying its long-lead material inventory over the coming years;
- anticipated Brent prices and fluctuations in Parex's realized price differential to Brent crude period over period;
- terms of certain of Parex's contractual obligations; and
- the Company's plans and expectations regarding the implementation of IFRS 18, including the assessment of system changes and the expected impact on financial statement presentation, management-defined performance measures and related disclosures.

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; an unpredictable tariff and trade environment; prolonged volatility and fluctuations in commodity prices; industry conditions including changes in laws and regulations such as the adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced in Canada and Colombia; determination by the Organization of Petroleum Exporting Countries and other countries as to production levels; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; imprecisions 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; geopolitical disruption including the U.S.-Iran conflict and the consequences arising therefrom; elevated energy costs and the risk that production expense may exceed guidance; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industries; ability to access sufficient capital from internal and external sources; 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; failure of counterparties to perform under the terms of their contracts; changes to pipeline capacity; the risk that Brent oil prices may be lower than anticipated; the risk that Parex's evaluation of its existing portfolio of development and exploration opportunities may not be consistent with its expectations; and that production test results may not be indicative of long-term performance or ultimate recovery; the risk that Parex may not have sufficient financial resources in the future to provide distributions to its shareholders; 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 may not be responsive to changes in commodity prices; 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 Parex may not meet its production or capital expenditure guidance for the year ended December 31, 2026; 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 senior officers in the event of departure; risk of failure to achieve the anticipated benefits associated with acquisitions, including risks related to the integration of the Frontera assets and the realization of the anticipated synergies and benefits therefrom; risks related to the business collaboration with Ecopetrol, including the satisfaction of conditions thereunder, the execution of the capital program, and the realization of anticipated benefits therefrom; the uncertainties and factors discussed under “Decommissioning and Environmental Liabilities” in this MD&A; 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, business environment and financial results is included in the "Risk Factors" section in the Company's AIF for the year ended December 31, 2025 and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca) or Parex's website at www.parexresources.com.

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 anticipated commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to areas of the Company's operations and infrastructure; future exchange rates; the price of oil, including the anticipated Brent oil price; 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; royalty rates; future operating costs; foreign exchange rates; the status of litigation; timing of drilling and completion of wells; receipt of partner, regulatory and community approvals; 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; that Parex's evaluation of its existing portfolio of development and exploration opportunities is consistent with its expectations; 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 production and reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; the successful integration of the Frontera assets and the realization of anticipated synergies and benefits therefrom; 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 to pay dividends and acquire shares pursuant to its NCIB in the future; 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 therefrom. Readers are cautioned not to place undue reliance on forward-looking information. 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 constitute a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to: Parex's H2 and FY 2026 guidance, including its anticipated capital expenditures and funds flow provided by operations; Parex's anticipated H2 2026 production, transportation and G&A expenses per boe including its expectation that combined operating expense and energy consumption expense will trend toward the upper end of the H2 2026 guidance range; 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; and the Company's estimated effective current tax rate for H2 2026 and FY 2026; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs and the key assumptions set forth under "Corporate Guidance". 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 is 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, and should not be used for purposes other than for which it is disclosed herein.

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 (including the Company's credit facility and note indentures) 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 and Gas 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. Light crude oil is crude oil with a relative density greater than 31.1 degrees API gravity, medium crude oil is crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity, and heavy crude oil is crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity. References to "crude oil" or "oil" in this MD&A include light and medium crude oil and heavy crude oil, and references to "natural gas" refer to conventional natural gas, each as defined in NI 51-101. Any references in this MD&A to production test rates or initial production rates are preliminary in nature, are not necessarily indicative of long-term performance or of ultimate recovery, and readers are cautioned not to place reliance on such rates in calculating the aggregate production of the Company.

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 National Instrument 52-112 - Non-GAAP and Other Financial Measures Disclosure), 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. The forward-looking non-GAAP financial measures used in this MD&A have no significant difference from their equivalent historical non-GAAP financial measures.

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 September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Property, plant and equipment expenditures	**$ 121,679**	$ 59,002	**$ 239,092**	$ 153,020
Exploration and evaluation expenditures	**40,091**	20,959	**147,414**	72,685
Capital expenditures	**$ 161,770**	$ 79,961	**$ 386,506**	$ 225,705

	For the three months ended					
($000s)	June 30, 2026	March 31, 2026	December 31, 2025	June 30, 2025	March 31, 2025	December 31, 2024
Property, plant and equipment expenditures	$ 69,131	$ 48,282	$ 47,575	$ 49,067	$ 44,951	$ 62,799
Exploration and evaluation expenditures	64,562	42,761	37,045	39,623	12,103	19,311
Capital expenditures	$ 133,693	$ 91,043	$ 84,620	$ 88,690	$ 57,054	$ 82,110

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 return of capital, such as the normal course issuer bid or dividends, without accessing outside funds and is calculated as follows:*

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Cash provided by operating activities	**$ 138,228**	$ 86,992	**$ 361,549**	$ 317,012
Net change in non-cash assets and liabilities	**58,113**	18,306	**80,548**	15,051
Funds flow provided by operations	**196,341**	105,298	**442,097**	332,063
Capital expenditures, excluding corporate acquisitions	**161,770**	79,961	**386,506**	225,705
Free funds flow	**$ 34,571**	$ 25,337	**$ 55,591**	$ 106,358

EBITDA*, is a non-GAAP financial measure that is defined as net income adjusted for finance income and expense, other expense, income tax expense 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, gain on acquisition, transaction costs, non-cash inventory fair value adjustment, 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 September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Net income	**$ 75,255**	$ 50,476	**$ 524,140**	$ 180,218
Adjustments to reconcile net income to EBITDA:				
Finance income	**(1,781)**	(1,306)	**(7,925)**	(3,215)
Finance expense	**36,281**	5,796	**60,265**	16,326
Other expense	**1,777**	3,815	**28,104**	17,415
Income tax expense	**30,505**	7,100	**7,163**	19,801
Depletion, depreciation and amortization	**100,551**	47,767	**214,222**	146,135
EBITDA	**$ 242,588**	$ 113,648	**$ 825,969**	$ 376,680
Share-based compensation expense	**15,595**	11,902	**33,921**	20,470
(Gain) loss on acquisition	**4,873**	—	**(297,610)**	—
Transaction costs	**—**	—	**29,000**	—
Non-cash inventory fair value adjustment	**—**	—	**9,365**	—
Unrealized foreign exchange gain	**(16,817)**	(4,246)	**(18,093)**	(11,534)
Unrealized gain on commodity risk management contracts	**—**	(172)	**(1,281)**	(1,332)
Unrealized gain on marketable securities	**(8,215)**	—	**(18,500)**	—
Adjusted EBITDA	**$ 238,024**	$ 121,132	**$ 562,771**	$ 384,284

***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 purchased crude oil, royalties, production 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 produced oil and gas sales volumes before consumption for oil and natural gas sales price, oil and natural gas sales price, net of purchased crude oil, royalties, production and transportation 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 before consumption. 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.*

***Adjusted funds flow provided by operations netback per boe,** is a non-GAAP ratio calculated as funds flow provided by operations, adjusted to exclude non-recurring transaction-related costs and realized (gains) losses on commodity risk management contracts, divided by produced oil and natural gas sales volumes before consumption. The Company considers adjusted funds flow provided by operations netback per boe to be a key measure as it demonstrates Parex's profitability after cash costs, excluding items that may not reflect ongoing operating performance, 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.*

***Basic and diluted adjusted funds flow provided by operations per share or adjusted FFO per share**, is a non-GAAP ratio that is calculated by dividing adjusted funds flow provided by operations by the weighted average number of basic and diluted shares outstanding. Parex presents basic and diluted adjusted funds flow provided by operations adjusted to exclude non-recurring transaction-related costs and realized (gains) losses on commodity risk management contracts 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 adjusted funds flow provided by operations per share or adjusted 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 excluding items that may not reflect ongoing operating performance, relative to current commodity prices.*

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.*

***Adjusted funds flow provided by operations,** is a capital management measure calculated as funds flow provided by operations, adjusted to exclude non-recurring transaction-related costs and realized (gains) losses on commodity risk management contracts. The Company considers adjusted funds flow provided by operations to be a key measure as it demonstrates Parex's profitability after cash costs, excluding items that may not reflect ongoing operating performance.*

A reconciliation from cash provided by operating activities to funds flow provided by operations and adjusted funds flow provided by operations is as follows:

	For the three months ended September 30,		For the nine months ended September 30,	
($000s)	**2026**	2025	**2026**	2025
Cash provided by operating activities	**$ 138,228**	$ 86,992	**$ 361,549**	$ 317,012
Net change in non-cash assets and liabilities	**58,113**	18,306	**80,548**	15,051
Funds flow provided by operations	**196,341**	105,298	**442,097**	332,063
Transaction costs	**—**	—	**29,000**	—
Realized loss on commodity risk management contracts	**—**	3,193	**—**	3,386
Adjusted funds flow provided by operations	**$ 196,341**	$ 108,491	**$ 471,097**	$ 335,449

	For the three months ended					
($000s)	June 30, 2026	March 31, 2026	December 31, 2025	June 30, 2025	March 31, 2025	December 31, 2024
Cash provided by operating activities	$ 199,235	$ 24,086	$ 107,744	$ 142,642	$ 87,621	$ 67,847
Net change in non-cash assets and liabilities	(67,181)	89,616	15,178	(37,821)	34,323	73,354
Funds flow provided by operations	132,054	113,702	122,922	104,821	121,944	141,201
Transaction costs	28,390	610	**—**	—	—	—
Realized loss (gain) on commodity risk management contracts	30,711	2,236	(807)	(1,168)	1,361	—
Adjusted funds flow provided by operations	$ 191,155	$ 116,548	$ 122,115	$ 103,653	$ 123,305	$ 141,201

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

	As at September 30,	
($000s)	**2026**	2025
Current assets	**$ 689,676**	$ 224,109
Current liabilities	**725,652**	227,276
Working capital deficit	**$ (35,976)**	$ (3,167)

	As at					
($000s)	June 30, 2026	March 31, 2026	December 31, 2025	June 30, 2025	March 31, 2025	December 31, 2024
Current assets	$ 602,247	$ 411,425	$ 273,994	$ 239,485	$ 259,256	$ 245,943
Current liabilities	685,469	275,919	245,967	219,437	190,216	186,546
Working capital surplus (deficit)	$ (83,222)	$ 135,506	$ 28,027	$ 20,048	$ 69,040	$ 59,397

Net debt (net cash), *is a capital management measure which the Company uses to monitor leverage and manage capital. Net debt (net cash) is defined as working capital, less bank debt, unsecured notes and long-term customer prepayments:*

	As at September 30,	
($000s)	**2026**	2025
Working capital deficit	**$ 35,976**	$ 3,167
Bank debt	**82,499**	10,000
Unsecured notes	**792,889**	—
Net debt	**$ 911,364**	$ 13,167

	As at					
($000s)	June 30, 2026	March 31, 2026	December 31, 2025	June 30, 2025	March 31, 2025	December 31, 2024
Working capital (surplus) deficit	$ 83,222	$ (135,506)	$ (28,027)	$ (20,048)	$ (69,040)	$ (59,397)
Bank debt	—	175,200	33,000	18,000	50,000	60,000
Unsecured notes	792,265	—	—	—	—	—
Customer prepayments - long-term	31,111	—	—	—	—	—
Net debt (net cash)	$ 906,598	$ 39,694	$ 4,973	$ (2,048)	$ (19,040)	$ 603

Supplementary Financial Measures

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

"Energy consumption expense per boe" is comprised of energy consumption expense, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

"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 total production.

"Net revenue per boe" is comprised of net revenue, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

"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 total equivalent produced oil and gas sales volumes before consumption.

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

"Operating expense per boe" is comprised of operating expense, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

"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 energy consumption expense and operating expense, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

"Purchased crude oil per bbl" is comprised of purchased crude oil expense, as determined in accordance with IFRS, divided by the total equivalent produced oil sales volumes before consumption.

"Purchased crude oil per boe" is comprised of purchased crude oil expense, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

"Realized oil sales price per bbl" is comprised of total oil sales, as determined in accordance with IFRS, divided by the total equivalent produced oil sales volumes before consumption.

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

"Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

"Royalties as a percentage of sales" is comprised of royalties, as determined in accordance with IFRS, divided by the total equivalent sales from produced oil and natural gas production, as determined in accordance with IFRS.

"Transportation expense per bbl" is comprised of transportation expense, as determined in accordance with IFRS, divided by the total equivalent produced oil sales volumes before consumption.

"Transportation expense per boe" is comprised of transportation expense, as determined in accordance with IFRS, divided by the total equivalent produced oil and gas sales volumes before consumption.

Business Environment and Risks

Parex is exposed to various market and operational risks. For a discussion of these risks please refer to the "Risk Factors" section in Parex's AIF for the year ended December 31, 2025 as filed on SEDAR+ at www.sedarplus.ca or Parex's website at www.parexresources.com.

Internal Controls over Financial Reporting

On June 1, 2026, Parex completed the acquisition of Sabana Petroleum International Holdings B.V. (formerly Frontera Petroleum International Holdings B.V.) (the "Frontera Transaction"), which holds all of its exploration and production assets in Colombia. The Company began consolidating the results of the acquired business effective June 1, 2026. In addition, on July 29, 2026, the Company completed the acquisition of interests in the Casabe and Llanito blocks through the executed agreement with its strategic partner Ecopetrol S.A. (the "Ecopetrol Strategic Partnership"). In connection with these acquisitions, management commenced activities to integrate the acquired operations, processes and systems into Parex's disclosure controls and procedures ("DCP") and internal control over financial reporting ("ICFR").

As permitted by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, management has limited the scope of its design of DCP and ICFR to exclude the controls, policies and procedures of the acquired businesses as at September 30, 2026. National Instrument 52-109 permits an issuer to limit the scope of the design of DCP and ICFR to exclude an acquired business for a period of up to 365 days from the acquisition date. During this period, management will continue its assessment and integration of the acquired business, including the design and implementation of appropriate controls.

At September 30, 2026, the acquired businesses represented approximately 32% of the Company's consolidated total assets and approximately 32% of the Company's consolidated oil and natural gas sales for the period from the respective acquisition dates of June 1, 2026 and July 29, 2026 to September 30, 2026.

Other than changes associated with the integration of the acquired businesses described above, there were no changes in the Company's ICFR during the period covered by this MD&A 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 nine months ended September 30, 2026 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 27 - Commitments and Contingencies in the unaudited condensed interim 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, marketable securities, accounts payable and accrued liabilities, customer prepayments, the senior secured credit facility and senior unsecured notes. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to the short-term nature of these instruments.. The fair value of the revolving credit facility approximates its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates. The fair value of the senior unsecured notes is determined based on quoted market prices and other observable market inputs and is classified as Level 2 within the fair value hierarchy.

Material Accounting Policies

The accounting policies adopted are consistent with those of the previous financial year as described in note 3 of the Company's consolidated financial statements for the year ended December 31, 2025 with the addition of the below Amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures.*

On January 1, 2026, the Company adopted the amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* in the interim period ending March 31, 2026. The amendments for disclosures relate to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. There was not a material effect to the Company's condensed interim consolidated financial statements. The Company has applied the election to deem financial liabilities settled in cash using an electronic payment system to be discharged before the settlement date. The amendments have been applied retrospectively with no restatement of comparative information, in accordance with transition requirements on initial application of IFRS 9. There is no adjustment to the opening balance of cash and cash equivalents in the consolidated statements of cash flows.

In addition, due to the acquisition of Sabana Petroleum International Holdings B.V. (formerly Frontera Petroleum International Holdings B.V.) (see Note 8 - Business Combinations), the following additional accounting policies have been updated:

Subsidiaries:
Sabana Resources Corp. (formerly Frontera Energy Colombia Corp.) has been identified as an additional principal operating subsidiary incorporated in Switzerland and its principal business activity is oil and natural gas exploration and development in Colombia. Parex has 100% ownership of this subsidiary.

Customer prepayments:
The Company recognizes each contract in the statement of financial position as either a contract asset or a contract liability, based on the relationship between the Company's performance under the contract and the consideration received from the customer. Additionally, when a customer pays consideration, or when the Company has an unconditional right to consideration (i.e., a receivable) before transferring goods or services, the entity shall present the amount as a contract liability or customer prepayment in the statement of financial position (see Note 13 - Customer Prepayments). This classification applies at the earlier of the payment date or the date the payment becomes due. Financing components embedded in customer prepayment arrangements are recognized using the effective interest method over the term of the agreement when significant financing components exist.

Other comprehensive income:
Other comprehensive income ("OCI") consists of items of income and expense that are recognized outside net income in accordance with IFRS Accounting Standards. OCI includes foreign currency translation differences arising from the translation of foreign operations, which may be reclassified to net income upon disposal of the relevant foreign operation. The income tax effects of items recognized in OCI are recognized in OCI, where applicable.

In addition, due to the closing of the Ecopetrol Strategic Partnership (see Note 8 - Business Combinations), the following accounting policy has been updated:

Deferred Consideration:
Deferred consideration is the Company's obligation to fund future capital expenditures under an acquisition arrangement, to the extent those expenditures relate to the participating interest acquired. At the acquisition date, it is recognized at fair value, measured as the present value of the expected future payments. After initial recognition, it is measured at amortized cost using the effective interest method, with accretion recognized in finance expense. The liability is reduced as the related expenditures are incurred. Changes in the estimated amount or timing of those expenditures are recognized in net income. Expenditures that earn the Company an additional participating interest are not part of the deferred consideration. They are capitalized to property, plant and equipment when incurred.

In addition, due to the recognition of Equity tax in the current period, the following additional accounting policy has been updated:

Equity tax:
Equity tax represents a tax imposed by the Colombian Government on entities whose net equity exceeds a prescribed threshold as of a specified measurement date. The tax is recognized as an expense when the obligating event occurs and the amount can be reliably estimated. The related liability is measured based on the applicable tax rate applied to taxable net equity, considering enacted or substantively enacted tax legislation at the reporting date. Equity tax is recognized in profit or loss and is not included in income tax expense unless required by applicable tax legislation (see Note 20 - Other Expense).

Standards Issued but not yet Effective

i) 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.

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. Refer to Note 2 of the audited consolidated financial statements for a summary of significant accounting estimates applied by the Company.

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Alberto Consuegra

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G.R (Bob) MacDougall

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

Cameron Grainger
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Eric Furlan
Chief Operating Officer

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbl(s)	barrel(s)
mbbls	one thousand barrels
bbl(s)/d or bopd	barrel(s) 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
FFO	Funds flow provided by operations