FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

March 17, 2026
For the year ended December 31, 2025

*Frontera Energy Corporation (“**Frontera**” , “**FEC**” or the “**Company**”) is an oil and gas company formed and existing under the laws of British Columbia, Canada, that is engaged in the exploration, development, production, transportation, storage and sale of crude oil and conventional natural gas in South America, including strategic investments in both upstream and infrastructure facilities, and is committed to working hand-in-hand with all its stakeholders to conduct business in a socially and environmentally responsible manner. The Company’s common shares (“**Common Shares**”) are listed and publicly traded on the Toronto Stock Exchange (“**TSX**”) under the trading symbol “FEC”. The Company’s head office is located at 1030, 140 – 4 Avenue SW, Calgary, Alberta, Canada, T2P 3N3.*

*This Management’s Discussion and Analysis (“**MD&A**”) is management’s assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Annual Consolidated Financial Statements and related notes for the years ended December 31, 2025 and 2024 (the **“2025 Annual Consolidated Financial Statements”**). Additional information with respect to the Company, including the Company’s quarterly and annual financial statements and its Annual Information Form (“**AIF**”), have been filed with Canadian securities regulatory authorities and are available on SEDAR+ at www.sedarplus.ca and on the Company’s website at www.fronteraenergy.ca. Information contained in or otherwise accessible through the Company’s website does not form a part of this MD&A and is not incorporated by reference into this MD&A.*

*The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards (“**IFRS**”) as issued by the International Accounting Standards Board, unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These non-IFRS financial measures are described in greater detail under the heading “Non-IFRS and Other Financial Measures” section on page 29.*

*This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to activities, events or developments that the Company believes, expects or anticipates will or may occur in the future. Forward-looking information is often identified by words or phrases such as “may”, “could”, “would”, “might”, “will”, “expects,” “anticipates,” “plans,” “estimates,” “projects,” “forecasts,” “believes,” “intends,” “possible,” “probable,” “scheduled,” “goal”, “objective”, or similar words or phrases. All information in this MD&A other than historical fact is forward-looking information and includes, without limitation, statements regarding the Company's performance, including the performance of its subsidiaries, expectations about strategies and goals, expected industry, market and economic conditions, estimates and/or assumptions in respect of the oil price environment, the U.S. trade tariffs affecting on numerous countries including Colombia, the impact of international conflicts including the war in Iran and the Russia-Ukraine conflict and related sanctions, the expected impact of measures that the Company has taken and continues to take or may take in response to these events, the expected sale of the Company’s Colombian upstream business, pursuant to the Parex Arrangement (as defined below) and the process and timing for such transaction, the expected use of proceeds of the Parex Arrangement including the potential return of capital to the Company’s Shareholders (as defined below), Frontera’s business following completion of the Parex Arrangement, the ability of the Frontera Energy Guyana Corp. ("**Frontera Guyana**") and CGX Resources Inc. ("**CGX Resources**", and together with Frontera Guyana, the “**Joint Venture**”) to reach an agreement with the Government of Guyana in respect of the Joint Venture’s interest in the agreements relating to the Corentyne block, the Company's goal of enhancing the value of its Common Shares and consideration forms of strategic initiatives (including the Restructuring Plan, as defined herein) and transactions in connection therewith, the expected saving in connection with the Restructuring Plan, expectations regarding the 2026 capital and production guidance, the completion and operational timing of the LPG (as defined below) project and projected EBITDA with respect thereto, the water handling capacity at SAARA (as defined below), the Company’s expected use of proceeds from the prepayment and commercial agreement with Chevron Products Company (**“Chevron”**), expectations regarding the Company’s ability to manage its liquidity and capital structure and generate sufficient cash to support operations, capital expenditures and financial commitments, the intentions of the Company with regard to its capital allocation decisions, the timing of release of restricted cash, the impact of fluctuations in the price of, and supply and demand for oil and conventional natural gas products, production levels, cash levels, reserves, capital expenditures (including plans and projects related to drilling, exploration activities, and infrastructure and the timing plan, cost savings, including General and Administrative (“**G&A**”) expense savings, and thereof), operating EBITDA, production costs, transportation costs, the restructuring and the impact thereof and obtaining regulatory approvals.*

Forward-looking information reflects the current expectations, assumptions and beliefs of the Company based on information currently available to it and considers the Company’s experience and its perception of historical trends, including expectations and assumptions relating to commodity prices and interest and foreign exchange rates; access to capital markets; the performance of assets and equipment; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; the development and execution of projects; and any health security or similar situation.

Although the Company believes that the assumptions inherent in the forward-looking information are reasonable, forward-looking information is not a guarantee of future performance and accordingly undue reliance should not be placed on such information. Forward-looking information is subject to a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to the Company. The actual results of the Company may differ materially from those expressed or implied by the forward-looking information, and even if such actual results are realized or substantially realized, there can be no assurance that they will have the expected consequences to, or effects on, the Company. Factors that could cause actual results or events to differ materially from current expectations include, among other things: volatility in market prices for oil and natural gas, the U.S. trade tariffs affecting numerous countries including Colombia, the impact of the Russia-Ukraine conflict and the conflict in the Middle East and economic sanctions related thereto, actions of the Organization of Petroleum Exporting Countries (“OPEC+”), the risk that the sale of the Colombian upstream business pursuant to the Parex Arrangement is not completed on the terms of within the timeframes currently contemplated or at all, the failure to obtain all necessary court, third-party, regulatory and shareholder approvals to complete the Parex Arrangement and the risk that the transaction may be varied, accelerated or terminated in certain circumstances, the failure to obtain shareholder approval for the return of capital, actions by other third parties including customers, suppliers, industry partners or relevant governmental or regulatory authorities, uncertainties associated with estimating and establishing oil and natural gas reserves and resources, liabilities inherent with the exploration, development, exploitation and reclamation of oil and natural gas, uncertainty of estimates of capital and operating costs, production estimates and estimated economic return, increases or changes to transportation costs, expectations regarding the Company’s ability to raise capital and to continually add reserves through acquisition and development, the Company’s ability to complete strategic initiatives or transactions to enhance the value of its common shares and the timing thereof, the Company's intent to continue to consider investor-focused initiatives, the Company’s ability to access additional financing; the ability of the Company to maintain its credit ratings, the ability of the Company to: meet its financial obligations and minimum commitments, fund capital expenditures and comply with covenants contained in the agreements that govern indebtedness, political developments in the countries where the Company operates, the uncertainties involved in interpreting drilling results and other geological data, geological, technical, drilling and processing problems, timing of receipt of government approvals, measures the Company may take in response to pandemics or similar events, and fluctuations in foreign exchange or interest rates and stock market volatility. In addition, no assurance can be given that an agreement will be reached with the Government of Guyana in respect of the Joint Venture’s interests in, and the petroleum prospecting license for, the Corentyne block, or as to the results of any ongoing discussions or legal processes relating to such matters.

All forward-looking information speaks only as of the date on which it is made and the Company disclaims any intent or obligation to update any forward-looking information, whether as a result of new information, future events or otherwise, unless required pursuant to applicable laws. Risks, uncertainties, assumptions and other factors that could cause actual results to differ materially from those anticipated in the forward-looking information are described under the headings “Forward-Looking Information” and “Risk Factors” in the Company’s AIF and under the heading “Risks and Uncertainties” in this MD&A. Although the Company has attempted to consider important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors and therefore results may not be as anticipated, estimated or intended.

*Certain information included or incorporated by reference in this MD&A may constitute future oriented financial information and financial outlook information (collectively, “**FOFI**”) within the meaning of applicable Canadian securities laws. FOFI has been prepared by management to provide an outlook of the Company’s activities and results and may not be appropriate for other purposes. Management believes that the FOFI has been prepared on a reasonable basis, reflecting management’s reasonable estimates and judgments; however, actual results of the Company’s operations and the resulting financial outcome may vary from the amounts set forth herein. Any FOFI speaks only as of the date on which it was made, and the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or otherwise, unless required by applicable laws.*

1. MESSAGE TO THE SHAREHOLDERS

The Company's two core businesses include: (i) its Colombia upstream onshore business; and (ii) its Colombian infrastructure business. Upon completion of the Parex Arrangement (as defined below), Frontera will own and operate the Colombian infrastructure business and will retain its interests in certain other non-Colombian assets, including its interest in Guyana.

Operations and Business Overview

2025 was a year of decisive execution and disciplined capital allocation, as Frontera delivered on its commitments and strengthened its financial position. The Company generated $308 million of Operating EBITDA and closed the year with $242 million of cash, providing a strong foundation to execute on its strategic priorities.

The Company's infrastructure business delivered another year of strong results. Oleoducto de los Llanos Orientales S.A. ("**ODL"**) transported over 238,000 bbl/d while generating approximately $300.0 million in full-year EBITDA (approximately $105 million attributable to Frontera based on its 35% equity interest). Through the equity interest in the pipeline, the Company received more than $62 million in cash distributions. Puerto Bahia generated approximately $15 million in operating EBITDA, broadly flat year-over-year, and setting the basis for growth in key dry terminal areas, including increased container activity, offsetting lower volumes from the liquids terminal. Looking ahead, Frontera will emerge as a newly focused infrastructure business, which will be the backbone of our post-transaction Frontera. The Company's infrastructure business generated 2025 Adjusted Infrastructure EBITDA and Distributable Cash Flows totaling $116.6 million and $76.7 million, respectively, supported by a stable dividend stream from ODL and an attractive growth profile at Sociedad Portuaria Puerto Bahia S.A ("**Puerto Bahia"**). Key growth initiatives include the LPG import facilities, a potential LNG regasification project and containerized cargo expansion. The LPG project is expected to achieve an early start-up later in March, and emerging opportunities like the LNG regasification project, supported by a binding take-or-pay agreement with Ecopetrol S.A ("**Ecopetrol**"), with an initial capacity of approximately 126 MMcfd, anticipated to increase to at least 300 MMcfd by 2029, shall continue to drive growth into 2026 and beyond.

Following year-end, Frontera entered into a definitive arrangement with Parex Resources Inc. and Parex AcquisitionCo Inc. (together "**Parex**" or "**Parex Purchaser**") for the divestment of its Colombian E&P assets, marking the successful culmination of a multi-year, comprehensive strategic process. This transaction crystallizes a $125 million increase in cash consideration to shareholders—a 31% improvement over the GeoPark outcome—while preserving significant long-term upside through its Infrastructure platform and retained assets.

Throughout this process, the Board remained focused on a clear objective: maximizing long-term shareholder value through disciplined evaluation, thoughtful engagement with counterparties, and careful stewardship of the Company's strategic options. The outcome reflects both the intrinsic quality of our team, assets and the strength of our positioning.

With this transaction, Frontera completes its transition into a focused infrastructure platform anchored by its interests in ODL and Puerto Bahia —high-quality assets that generate stable cash flows and offer attractive growth opportunities.

Subject to closing, the Company expects to return approximately $470 million to shareholders, representing a substantial return of capital, while retaining the financial flexibility to invest in high-conviction growth initiatives, including its LNG regasification project with Ecopetrol.

In total, this strategy will have unlocked approximately $1.3 billion of capital for shareholders. Frontera now enters its next phase as a more focused, cash-generative infrastructure company, well positioned to deliver durable returns and continued value creation.

"Orlando Cabrales Segovia" (signed)
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary *

		Q4 2025	Q3 2025	Q4 2024	Year ended December 31 2025	Year ended December 31 2024
Operational Results from Continuing Operations						
Heavy crude oil production [(1)]	(bbl/d)	26,696	27,078	27,740	27,118	25,328
Light and medium crude oil combined production [(1)]	(bbl/d)	8,918	9,235	10,484	9,381	10,882
Total crude oil production	(bbl/d)	35,614	36,313	38,224	36,499	36,210
Conventional natural gas production [(1)]	(mcf/d)	5,261	4,406	2,633	3,773	3,278
Natural gas liquids production [(1)]	(boe/d) [(3)]	1,795	1,848	1,970	1,850	1,838
Total production Colombia [(2)]	(boe/d) [(3)]	38,332	38,934	40,656	39,011	38,623
Total inventory balance of Colombia and Peru	(bbl)	860,362	919,914	1,029,466	860,362	981,978
Brent price reference	($/bbl)	63.08	68.17	74.01	68.19	81.82
Produced crude oil and gas sales [(4)]	($/boe)	59.52	64.40	67.31	63.86	72.95
Purchased crude net margin [(4)(5)]	($/boe)	(2.27)	(2.70)	(3.55)	(3.12)	(3.25)
Oil and gas sales, net of purchases [(4)(5)]	($/boe)	57.25	61.70	63.76	60.74	69.70
(Loss) gain on oil price risk management contracts [(6)(7)]	($/boe)	(0.38)	(1.20)	0.08	(0.72)	(0.72)
Royalties [(6)]	($/boe)	(0.73)	(0.78)	(0.80)	(0.79)	(1.26)
Net sales realized price [(4)(5)]	($/boe)	56.14	59.72	63.04	59.23	67.72
Production costs (excluding energy costs), net of realized FX hedge impact [(4)]	($/boe)	(9.64)	(8.46)	(7.60)	(9.23)	(9.39)
Energy costs, net of realized FX hedge impact [(4)]	($/boe)	(6.22)	(5.56)	(5.46)	(5.49)	(5.26)
Transportation costs, net of realized FX hedge impact [(4)(5)]	($/boe)	(11.92)	(11.72)	(11.59)	(12.00)	(11.80)
Operating netback from Continuing Operations per boe [(4)(5)]	($/boe)	28.36	33.98	38.39	32.51	41.27
Financial Results						
Oil & gas sales, net of purchases [(8)]	($M)	177,038	194,153	207,518	727,544	815,993
(Loss) gain on oil price risk management contracts [(7)]	($M)	(1,186)	(3,784)	253	(8,680)	(8,457)
Royalties	($M)	(2,241)	(2,454)	(2,599)	(9,448)	(14,704)
Net sales [(8)]	($M)	173,611	187,915	205,172	709,416	792,832
Net (loss) income for the period from continuing operations [(9)]	($M)	(663,354)	28,235	(20,485)	(1,020,361)	(18,628)
Net income (loss) for the period from discontinued operations	($M)	2,905	(2,818)	(8,916)	(42,359)	(5,534)
Net (loss) income for the period [(9)]	($M)	(660,449)	25,417	(29,401)	(1,062,720)	(24,162)
Per share – diluted from continuing operations	($)	(9.51)	0.38	(0.25)	(13.77)	(0.22)
Per share – diluted from discontinued operations	($)	0.04	(0.04)	(0.11)	(0.57)	(0.07)
General and administrative	($M)	15,898	14,877	11,820	58,174	50,292
Outstanding Common Shares	Number of Shares	69,530,049	69,833,514	80,793,387	69,530,049	80,793,387
Operating EBITDA from continuing operations [(8)]	($M)	68,907	86,585	109,620	308,029	405,118
Cash provided by operating activities	($M)	195,486	115,034	168,691	422,443	508,152
Capital expenditures [(8)]	($M)	53,247	50,859	84,544	209,193	290,684
Cash and cash equivalents – unrestricted	($M)	230,489	158,614	192,577	230,489	192,577
Restricted cash short and long-term [(10)]	($M)	11,320	13,437	30,249	11,320	30,249
Total cash [(10)]	($M)	241,809	172,051	222,826	241,809	222,826
Total debt and lease liabilities [(10)]	($M)	493,909	532,789	506,037	493,909	506,037
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(11)]	($M)	429,256	357,228	414,481	429,256	414,481
Net debt (excluding Unrestricted Subsidiaries) [(11)]	($M)	219,531	252,640	277,298	219,531	277,298

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 19 for further details.

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

(2) Represents W.I. production before royalties. Refer to the “Further Disclosures” section on page 46 for further details.

(3) Boe has been expressed using the 5.7 to 1 Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy. Refer to the “Further Disclosures - Boe Conversion” section on page 46 for further details.

(4) Non-IFRS ratio is equivalent to a “non-GAAP ratio”, as defined in National Instrument 52-112 - *Non-GAAP and Other Financial Measures Disclosure (“***NI 52-112***”)*. Refer to the “Non-IFRS and Other Financial Measures” section on page 29 for further details.

(5) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(6) Supplementary financial measure (as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures” section on page 29 for further details.

(7) Includes the net effect of put premiums paid for expired positions and positive cash settlements received from oil price contracts during the period. Refer to the “Gain (Loss) on Risk Management Contracts” section on page 18 for further details.

(8) Non-IFRS financial measure (equivalent to a “non-GAAP financial measure”, as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures” section on page 29 for further details.

(9) (loss) income attributable to equity holders of the Company.

(10) Capital management measure (as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures” section on page 29 for further details.

(11) “**Unrestricted Subsidiaries**” include CGX Energy Inc. (“**CGX**”), listed on the TSX Venture Exchange under the trading symbol “OYL”; FEC ODL Holdings Corp., including its subsidiary, Frontera Pipeline Investment AG (“**FPI**”, formerly named Pipeline Investment Ltd); Frontera BIC Holding Ltd.; Frontera Energy Guyana Holding Ltd.; Frontera Energy Guyana Corp.; and Frontera Bahía Holding Ltd., including Puerto Bahia. Refer to the “Liquidity and Capital Resources” section on page 35 for further details.

Performance Highlights

Full Year 2025

- Colombia Production averaged 39,011 boe/d in 2025 (consisting of 27,118 bbl/d of heavy crude oil, 9,381 bbl/d of light and medium crude oil combined, 3,773 mcf/d of conventional natural gas and 1,850 boe/d of natural gas liquids), compared with 38,623 boe/d in 2024 (consisting of 25,328 bbl/d of heavy crude oil, 10,882 bbl/d of light and medium crude oil combined, 3,278 mcf/d of conventional natural gas and 1,838 boe/d of natural gas liquids).

- Cash provided by operating activities was $422.4 million in 2025, compared with $508.2 million in 2024, contributing to a total cash position as at December 31, 2025, of $241.8 million, compared with $222.8 million as at December 31, 2024. Total cash includes $11.3 million of restricted cash, compared with $30.2 million as at December 31, 2024.

- Net loss [1] was $1,062.7 million ($13.77/share[2]) in 2025, net of a non-cash impairment expenses of $1,063.2 million, compared with a net loss [1] of $24.2 million ($0.22/share[2]) in 2024.

- Capital expenditures were $209.2 million in 2025, compared with $290.7 million in 2024.

- Operating EBITDA was $308.0 million in 2025, compared with $405.1 million in 2024.

- Operating netback was $32.51/boe in 2025, compared with $41.27/boe in 2024.

- Infrastructure Colombia Segment (as defined below) income was $41.0 million in the 2025, compared with $55.5 million in 2024.

- Adjusted Infrastructure EBITDA was $116.6 million in 2025, compared with $107.2 million in 2024.

- Puerto Bahia liquids volumes handled during the year 2025 were 46,193 bbl/d compared to 56,020 bbl/d in 2024.

- ODL volumes transported were 238,994 bbl/d in 2025, compared to 243,669 bbl/d in 2024.

Fourth Quarter 2025

- Total Colombia production averaged 38,332 boe/d in the fourth quarter of 2025 (consisting of 26,696 bbl/d of heavy crude oil, 8,918 bbl/d of light and medium crude oil combined, 5,261 mcf/d of conventional natural gas and 1,795 boe/d of natural gas liquids), compared with 38,934 boe/d in the prior quarter (consisting of 27,078 bbl/d of heavy crude oil, 9,235 bbl/d of light and medium crude oil combined, 4,406 mcf/d of conventional natural gas and 1,848 boe/d of natural gas liquids), and compared with 40,656 boe/d in the fourth quarter of 2024 (consisting of 27,740 bbl/d of heavy crude oil, 10,484 bbl/d of light and medium crude oil combined, 2,633 mcf/d of conventional natural gas and 1,970 boe/d of natural gas liquids).
- Cash provided by operating activities was $195.5 million in the fourth quarter of 2025, compared with $115.0 million in the prior quarter, and $168.7 million in the fourth quarter of 2024. The Company reported a total cash position of $241.8 million, including $11.3 million of restricted cash, as at December 31, 2025, compared with a total cash position of $172.1 million, including $13.4 million of restricted cash, as at September 30, 2025 , and $222.8 million, including $30.2 million of restricted cash, as at December 31, 2024.
- The Company recorded a net loss, attributable to equity holders of the Company, from continuing operations of $663.4 million ($9.51/share[1]) in the fourth quarter of 2025, compared with a net income, attributable to equity holders of the Company, from continuing operations of $28.2 million, ($0.38/share[1]) in the prior quarter, and a net loss, attributable to equity holders of the Company, from continuing operations of $20.5 million ($0.25/share[1]) in the fourth quarter of 2024.
- Capital expenditures were $53.2 million in the fourth quarter of 2025, compared with $50.9 million in the prior quarter and $84.5 million in the fourth quarter of 2024.
- Operating EBITDA from continuing operations was $68.9 million in the fourth quarter of 2025, compared with $86.6 million in the prior quarter and $109.6 million in the fourth quarter of 2024.
- Operating netback from continuing operations was $28.36/boe in the fourth quarter of 2025, compared with $33.98/boe in the prior quarter and $38.39/boe in the fourth quarter of 2024.
- Infrastructure Colombia Segment (as defined below) loss was $4.1 million in the fourth quarter of 2025, compared with $15.5 million in the prior quarter and $15.2 million in the fourth quarter of 2024.
- Adjusted Infrastructure EBITDA in the fourth quarter of 2025 was $30.5 million, compared with $30.4 million in the prior quarter and $27.5 million in the fourth quarter of 2024.

- Puerto Bahia liquid volumes handled during the fourth quarter of 2025 were 40,548 bbl/d, compared with 39,560 bbl/d in the prior quarter and 61,990 bbl/d in the fourth quarter of 2024. Puerto Bahia revenues were $12.8 million in the fourth quarter of 2025, compared with $12.0 million in the prior quarter and $11.5 million in the fourth quarter of 2024.
- ODL volumes transported were 241,734 bbl/d in the fourth quarter of 2025, compared with 241,958 bbl/d in the prior quarter, and 235,528 bbl/d in the fourth quarter of 2024.

(1) (Loss) income attributable to equity holders of the Company.
(2) Per Common Share on a diluted basis from continuing operations.

Oil and Gas Reserves

- Frontera added 1.6 MMboe of 2P gross reserves, for total Company 2P gross reserves of 133.8 MMboe and a reserve life index of 9.4 years at year end 2025.
- Frontera's 2025 year-end gross 2P reserves include total additions of 3.5 MMboe by technical revisions, mainly in the CPE-6 block, Quifa block, Cubiro block, VIM-1 block and the Guatiquia block; offset by production of 14.2 MMboe, and 5.4 MMboe mainly associated with the planned disposition of the Caruto, Corcel E, Cernícalo, Petirrojo, Petirrojo Sur, Tijereto Sur and Entrerríos fields in Colombia and Perico and Espejo blocks in Ecuador. Proved gross reserves of 94.4 MMboe represent 71% of the total 2P reserves, an increase from 66% of the total 2P reserves in 2024.

Parex Arrangement

On January 29, 2026, Frontera, GeoPark and GeoPark Colombia SLU, a wholly-owned subsidiary of GeoPark ("**GeoPark Purchaser**"), entered into an arrangement agreement (the "**GeoPark Arrangement Agreement**") pursuant to which GeoPark agreed to acquire, through GeoPark Purchaser's acquisition of all of the outstanding shares of common stock of Frontera Petroleum International Holdings B.V., all of Frontera's Colombian upstream business, which consists of all of Frontera's oil and gas exploration and production assets in Colombia, its reverse osmosis water treatment facility and its palm oil plantation (collectively, the "**Frontera E&P Assets**") pursuant to a court-approved plan of arrangement under the Business Corporations Act (British Columbia) (the "**GeoPark Arrangemen**t").

On March 10, 2026, as a result of a binding offer from Parex which the Board determined to be a "Superior Proposal" under the terms of the GeoPark Arrangement Agreement, Frontera: (i) terminated the GeoPark Arrangement Agreement in accordance with its terms; and (ii) concurrently entered into an arrangement agreement with Parex, pursuant to which Parex has agreed to acquire, through Parex Purchaser's acquisition of all of the outstanding shares of common stock of Frontera Petroleum International Holdings B.V., the Frontera E&P Assets, pursuant to a court-approved plan of arrangement under the Business Corporations Act (British Columbia) (the "**Parex Arrangement**"). In connection with the termination of the GeoPark Arrangement Agreement, Frontera paid a break fee of $25,000,000 to GeoPark pursuant to the terms of the GeoPark Arrangement Agreement.

Under the Parex Arrangement Agreement, Parex Purchaser will, subject to the satisfaction of certain closing conditions, acquire the Frontera E&P Assets for a purchase price of: (i) $500,000,000; plus (ii) an additional $25,000,000 if the term of Frontera's contract in respect of Quifa area is extended prior to the first anniversary of the completion of the Parex Arrangement (collectively, the "**Purchase Price**"). The Purchase Price is subject to customary closing adjustments.

The Parex Arrangement also provides that Parex Purchaser, or an affiliate thereof, will assume all of the obligations under Frontera's outstanding 2028 Unsecured Notes (as defined below), as well as the $80,000,000 outstanding under the prepayment facility with Chevron Products Company.

Additional information regarding the Parex Arrangement is contained in the Company's material change report dated March 13, 2026, and the Company's annual information form for the year ended December 31, 2025, which are available on the Company's SEDAR+ profile at www.sedarplus.ca. Additionally, a copy of the Arrangement Agreement has been filed on the Company's SEDAR+ profile.

3. GUIDANCE

The Company's 2025 financial and operational results were generally in-line with all 2025 annual updated guidance metrics (the "**2025 Guidance**").

In 2025, production averaged 39,011 boe/d, in-line with the Company's 2025 Guidance of 39,000 to 39,500 boe/d. Production costs (excluding energy costs), net of realized FX hedge impact, were $9.23/boe in-line with 2025 Guidance range of $8.75/boe to $9.25/boe. Energy costs, net of realized FX hedge impact, of $5.49/boe were below the midpoint of the 2025 Guidance range of $5.25/boe to $5.75/boe. Transportation costs of $12.00/boe were below the lower end of the 2024 Guidance range of $12.50 to $13.00, primarily due to the optimization of transportation routes and pipeline agreements.

Operating EBITDA in 2025 totaled $308 million within the 2025 Guidance range at $65/bbl.

Capital expenditures of $209 million in 2025 were consistent with the 2025 Guidance of $200-223 million.

The following table reports the Company's 2025 updated guidance as well as its results for the year ended December 31, 2025:

Guidance Metrics	Unit	2025 Updated Guidance	Actual *
Average Daily Production (1)	boe/d	39,000 - 39,500	39,011
Production Costs (2)(4)	$/boe	8.75 - 9.25	9.23
Energy Costs (2)(4)	$/boe	5.25 - 5.75	5.49
Transportation Costs (3)(4)	$/boe	12.50 - 13.00	12.00
Operating EBITDA from Continuing Operations (5) at $65/bbl (6)	$MM	270 - 315	308
Operating EBITDA from Continuing Operations (5) at $70/bbl (6)	$MM	320 - 360	
Adjusted Infrastructure EBITDA (5)	$MM	110 - 125	116.6
Development Drilling	$MM	95 - 100	96.7
Development Facilities	$MM	60 - 65	62.5
Colombia Development	$MM	155 - 165	159.2
Colombia Exploration	$MM	30 - 35	31
Other (7)	$MM	2 - 5	2.7
Total Colombia Capex	$MM	187 - 205	192.9
Guyana Exploration	$MM	1 - 3	0.5
Colombia Infrastructure	$MM	12 - 15	15.7
Total Capital Expenditures from Continuing Operations (5)	$MM	200 - 223	209.1

* The figures correspond only to continuing operations, following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

(1) The Company's 2025 updated average production guidance range reflects its gross W.I. production before royalties and does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2025.

(2) Per-bbl/boe metric on a share before royalties' basis.

(3) Calculated using net production after royalties.

(4) Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 29 for further details.

(5) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 29 for further details.

(6) 2025 Updated Guidance Operating EBITDA from continuing operations calculated at Brent between $70/bbl and $65/bbl, and COP/USD exchange rate of 4,150:1.

(7) Other includes HSEQ activities and new field production technologies.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2025, the Company received an independent certified reserves evaluation report ("**Reserves Report**") from DeGolyer and MacNaughton for all of its assets, with total gross 2P reserves of 133.8 MMboe compared with 151.3 MMboe in **2024**. All of the Company's reserves for 2025 are located in Colombia [1].

Frontera's 2025 year-end gross 2P reserves include total additions of 1.6 MMboe by technical revisions, mainly in the CPE-6 and Guatiquia blocks; offset by production of 14.2 MMboe. Proved gross reserves of 94.4 MMboe represent 71% of the total 2P reserves, an increase from 66% of the total 2P reserves in 2024.

The Reserves Report was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook, NI 51-101 and CSA Staff Notice 51-324– *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities.*

Concurrently with the filing of this MD&A, the Company has filed the following: (i) the Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1, (ii) the Report on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101F2 by DeGolyer and MacNaughton, and (iii) the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3. These reports have been filed on SEDAR+ at www.sedarplus.ca.

Reserves at December 31, 2024 (MMboe[2])								
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Quifa SW block	28.9	26.8	4.9	4.5	33.9	31.3	Heavy Crude Oil
	CPE-6 block	28.6	26.3	9.4	8.6	38.0	34.9	Heavy Crude Oil
	Other heavy oil blocks [3]	15.4	14.8	4.4	4.3	19.9	19.1	Heavy Crude Oil
	Light/medium oil blocks [4]	10.1	10.4	14.9	14.5	25.1	24.9	Light and Medium Crude Oil Combined
	Natural gas blocks [5]	9.4	9.4	4.4	4.4	13.8	13.8	Conventional Natural Gas
	Natural gas blocks [5]	1.9	0.3	1.4	0.1	3.2	0.4	Natural Gas Liquids
	Total at Dec. 31, 2025	**94.4**	**88.0**	**39.5**	**36.5**	**133.8**	**124.5**	**Oil, Conventional Natural Gas and Natural Gas Liquids**
	Total at Dec. 31, 2024	**100.6**	**92.3**	**50.7**	**45.9**	**151.3**	**138.1**	
	Difference	(6.3)	(4.2)	(11.2)	(9.4)	(17.5)	(13.6)	
	2025 Production [6]	**14.2**	**13.0**	**Total reserves incorporated**		**3.3**	**0.6**	

[1] The Company's reserves for 2024 included reserves located in Ecuador. However, the Company agreed on July 31, 2025, to sell its 50% interest in the Perico and Espejo blocks in Ecuador. After receiving government approval on November 25, 2025, and ultimately upon execution of a public deed on December 9, 2025, the transaction was fully completed.

[2] See the "Further Disclosures - Boe Conversion" section on page 46.

[3] Includes the Cajua and Jaspe fields in the Quifa block, and the Sabanero block.

[4] Includes the Cubiro, Cravoviejo, Canaguaro, Guatiquia, Casimena, Corcel, Cachicamo and other producing blocks.

[5] Includes the VIM 1 and El Dificil blocks.

[6] Gross production distribution: heavy crude oil 9.9 MMboe, light & medium crude oil combined 3.4 MMboe, conventional natural gas 0.2 MMboe and natural gas liquids 0.7 MMboe.

[7] In the table above, "Gross" refers to W.I. before royalties, and "Net" refers to W.I. after royalties. Numbers in the table may not add due to rounding differences.

5. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average of total gross W.I. production before royalties from the Company's operations. Refer to the "Further Disclosures" section on page 46 for details of the Company's net production:

		Production				
					Year ended December 31	
Production from Continuing Operations:		**Q4 2025**	**Q3 2025**	**Q4 2024**	**2025**	**2024**
Producing blocks in Colombia						
Heavy crude oil	(bbl/d)	26,696	27,078	27,740	27,118	25,328
Light and medium crude oil combined	(bbl/d)	8,918	9,235	10,484	9,381	10,882
Conventional natural gas	(mcf/d)	5,261	4,406	2,633	3,773	3,278
Natural gas liquids	(boe/d)	1,795	1,848	1,970	1,850	1,838
Total production Colombia	**(boe/d)**	**38,332**	**38,934**	**40,656**	**39,011**	**38,623**
Production from Discontinued Operations [(1)]:						
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	848	940	1,750	1,131	1,665
Total production Ecuador	**(bbl/d)**	**848**	**940**	**1,750**	**1,131**	**1,665**

[(1)] The Company agreed on July 31, 2025, to sell its 50% interest in the Perico and Espejo blocks located in Ecuador. After receiving government approval on November 25, 2025, and ultimately upon execution of a public deed on December 9, 2025, the transaction was fully completed. Refer to the "Discontinued Operations" section on page 19 for further details.

For the year ended December 31, 2025, average daily production in Colombia increased by 388 boe/d compared to the same period of 2024**.** This increase was mainly driven by (i) an increase of 1,790 bbl/d in heavy crude oil production, resulting from the successful development drilling campaigns in the CPE-6 and Quifa blocks, the strong performance of the wells drilled during the late-2024 campaign in the Sabanero block, water-handling facilities in the CPE-6 block; and increased water processing capacity at SAARA, which supports production levels from the Quifa block, (ii) an increase of 15% in conventional natural gas production, as a result of commercialized volumes of natural gas from the VIM-1 block, and (iii) a natural gas liquids production increase of 1%. These increases were partially offset by the decreases in light and medium crude oil combined production by 14% due to natural decline.

For the three months ended December 31, 2025, production in Colombia decreased by 2,324 boe/d compared to the same period of 2024 and by 602 boe/d compared to the previous quarter**,** mainly due to (i) a 4% and 1% decline in heavy crude oil production, respectively, resulting from equipment and well failures in heavy oil fields and community blockades in the Sabanero block, and (ii) light and medium crude oil combined, and natural gas liquids production decreased mainly due to natural decline. These were partially offset by increases in conventional natural gas production driven by the commercialization of natural gas volumes from the VIM-1 block.

Production from Continuing Operations Reconciled to Sales Volumes *

The following table reconciles the Company's gross W.I. average production to net average production after payment of in-kind royalties to sales volumes, net of purchases, and summarizes other factors that impacted total sales volumes.

					Year ended December 31	
		Q4 2025	**Q3 2025**	**Q4 2024**	**2025**	**2024**
Production Colombia	(boe/d)	**38,332**	**38,934**	**40,656**	**39,011**	**38,623**
Royalties in-kind Colombia	(boe/d)	(3,060)	(3,413)	(3,948)	(3,437)	(4,404)
Net production Colombia	(boe/d)	**35,272**	**35,521**	**36,708**	**35,574**	**34,219**
Oil inventory draw	(boe/d)	649	2,060	2,993	334	135
Volumes purchased	(boe/d)	7,924	6,664	6,420	7,640	7,440
Other inventory movements (1)	(boe/d)	(2,786)	(2,906)	(2,150)	(2,833)	(2,448)
Sales volumes	(boe/d)	**41,059**	**41,339**	**43,971**	**40,715**	**39,346**
Sale of volumes purchased	(boe/d)	(7,447)	(7,134)	(8,595)	(7,902)	(7,358)
Sales volumes, net of purchases	(boe/d)	**33,612**	**34,205**	**35,376**	**32,813**	**31,988**
Oil sales volumes	(bbl/d)	32,705	33,406	34,929	32,171	31,421
Conventional natural gas sales volumes	(mcf/d)	5,170	4,554	2,548	3,658	3,232
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**33,612**	**34,205**	**35,376**	**32,813**	**31,988**
Inventory balance						
Colombia (2)	(bbl)	380,162	439,714	501,778	380,162	501,778
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Inventory ending balance from continuing operations	**(bbl)**	**860,362**	**919,914**	**981,978**	**860,362**	**981,978**
Ecuador (3)	(bbl)	—	22,422	47,488	—	47,488
Inventory ending balance from discontinued operations	**(bbl)**	**—**	**22,422**	**47,488**	**—**	**47,488**

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

(1) Mainly corresponds to operational consumption and quality volumetric compensation.

(2) Includes 0.24 MMbbl of oil produced and 0.14 MMbbl of diluent in the fourth quarter of 2025, 0.35 MMbbl of oil produced and 0.09 MMbbl of diluent in the third quarter of 2025, and 0.25 MMbbl of oil produced and 0.25 MMbbl of diluent in the fourth quarter of 2024.

(3) The Company agreed on July 31, 2025, to sell its 50% interest in the Perico and Espejo blocks located in Ecuador. After receiving government approval on November 25, 2025, and ultimately upon execution of a public deed on December 9, 2025, the transaction was fully completed. Refer to the "Discontinued Operations" section on page 19 for further details.

For the year ended December 31, 2025, sales volumes, net of purchases, increased by 3% compared to the same period of 2024, primarily driven by higher oil and gas production and inventory drawdowns. For three months ended December 31, 2025, sales volumes, net of purchases, decreased by 5% and 2% compared to the same period of 2024 and the previous quarter, respectively, mainly due to lower net oil production.

Realized and Reference Prices from Continuing Operations *

					Year ended December 31	
		Q4 2025	Q3 2025	Q4 2024	2025	2024
Reference price						
Brent [1]	($/bbl)	63.08	68.17	74.01	68.19	81.82
Average realized prices						
Realized oil price, net of purchases [2]	($/bbl)	57.19	61.95	64.08	61.00	70.30
Realized conventional natural gas price	($/mcf)	10.42	8.98	6.78	8.45	6.37
Net sales realized price						
Produced crude oil and gas sales [3]	($/boe)	59.52	64.40	67.31	63.86	72.95
Purchased crude net margin [2][3]	($/boe)	(2.27)	(2.70)	(3.55)	(3.12)	(3.25)
Oil and gas sales, net of purchases [3]	($/boe)	57.25	61.70	63.76	60.74	69.70
(Loss) gain on oil price risk management contracts [4] [5]	($/boe)	(0.38)	(1.20)	0.08	(0.72)	(0.72)
Royalties [4]	($/boe)	(0.73)	(0.78)	(0.80)	(0.79)	(1.26)
Net sales realized price [3]	**($/boe)**	**56.14**	**59.72**	**63.04**	**59.23**	**67.72**

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 19 for further details.

(1) Frontera’s weighted average Brent price for the three months and the year ended December 31, 2025, was $63.25/bbl and $68.13/bbl, respectively.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Non-IFRS ratio. Refer to the “Non-IFRS and Other Financial Measures’’ section on page 29 for further details. Corresponds to the net sales and costs of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes, as part of the Company’s oil operations, marketing and transportation strategy.

(4) Supplementary financial measure. Refer to the “Non-IFRS and Other Financial Measures’’ section on page 29 for further details.

(5) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the “Gain (Loss) on Risk Management Contracts” section on page 18 for further details.

The average Brent benchmark oil price during the three months and the year ended December 31, 2025, decreased by 15% and 17%, respectively, compared to the same periods of 2024. Compared with the third quarter of 2025, the average Brent benchmark oil price decreased by 7%. The decrease in crude oil prices in 2025 was mainly due to: (i) OPEC+ accelerated the unwinding of production cuts during the second quarter of 2025 and commenced the second phase of the unwinding process, which continued to increase global oil supply, which continues to increase global oil supply, along with additional output from Brazil, Guyana, Argentina and Canada; (ii) ongoing tariff negotiations involving the U.S., Canada, China, Europe and Latin America have negatively impacted market demand sentiment; and (iii) the war risk premium has been lower than anticipated and has not yet materialized. Frontera’s oil price differentials have narrowed, despite the return of Venezuelan crude to the market following Chevron’s license renewal.

For the three months and the year ended December 31, 2025, the Company’s net sales realized price decreased by $6.90/boe and $8.49/boe, respectively, compared to the same periods of 2024, primarily due to lower Brent benchmark oil price, partially offset by better oil price differentials and lower cash royalties paid. Compared with the prior quarter, the Company’s net realized sales price decreased by 6%, primarily driven by a lower Brent benchmark oil price and lower oil price differentials partially offset by lower oil price risk management contracts.

Operating Netback from Continuing Operations *

The following table provides a summary of the Company's quarterly operating netback from continuing operations for the following periods:

	Q4 2025		Q3 2025		Q4 2024	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price [(1)]	173,611	56.14	187,915	59.72	205,172	63.04
Production costs (excluding energy costs), net of realized FX hedge impact [(1)(2)(3)]	(33,998)	(9.64)	(30,301)	(8.46)	(28,411)	(7.60)
Energy costs, net of realized FX hedge impact [(1)(2)(4)]	(21,918)	(6.22)	(19,900)	(5.56)	(20,439)	(5.46)
Transportation costs, net of realized FX hedge impact [(1)(2)(5)]	(38,670)	(11.92)	(38,316)	(11.72)	(39,152)	(11.59)
Operating Netback from Continuing Operations [(1)(2)(6)]	**79,025**	**28.36**	**99,398**	**33.98**	**117,170**	**38.39**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases [(7)]		33,612		34,205		35,376
Production Colombia [(8)]		38,332		38,934		40,656
Net production Colombia [(9)]		35,272		35,521		36,708

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.

(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.

(3) Includes gain of $1.4 million, $1.2 million and $Nil from realized FX hedge attributable to production costs for the fourth quarter of 2025, the third quarter of 2025, and fourth quarter of 2024, respectively. See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

(4) Includes gain of $0.7 million, $0.7 million and $Nil from realized FX hedge attributable to energy costs for the fourth quarter of 2025, the third quarter of 2025, and fourth quarter of 2024, respectively. See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

(5) Includes gain of $0.8 million, $0.9 million and $Nil from realized FX hedge attributable to transportation costs for the fourth quarter of 2025, the third quarter of 2025, and fourth quarter of 2024, respectively. See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

(6) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(7) Sales volumes, net of purchases, excluding sales of third-party volumes.

(8) Refer to the "Production Colombia" section on page 8 for further details.

(9) Refer to the "Further Disclosures" section on page 46 for further details.

The Company's operating netback from continuing operations for the fourth quarter of 2025 was $28.36/boe, lower than $38.39/boe in the same period of 2024, primarily due to a lower Brent benchmark oil price. Compared to the third quarter of 2025, operating netback from continuing operations decreased from $33.98/boe to $28.36/boe. The Company's operating netback decreased quarter-over-quarter mainly due to: (i) a lower net sales realized price; (ii) an increase in production costs (excluding energy costs), net of realized FX hedge impact, primarily driven by higher well service activity and the impact of the strong Colombian peso, (iii) higher transportation costs, net of realized FX hedge impact, mainly to increased transported volumes resulting from inventory drawdowns; and (iv) higher energy costs, net of realized FX hedge impact, primarily due to higher fuel consumption resulting from higher processed production liquid volumes and the impact of the strong Colombian peso.

The following table provides a summary of the Company's netbacks from continuing operations for the year ended December 31, 2025, and 2024:

	Year ended December 31			
	2025		2024	
	$M	($/boe)	$M	($/boe)
Net sales realized price [1]	709,416	59.23	792,832	67.72
Production costs (excluding energy costs), net of realized FX hedge impact [1][2][3]	(131,464)	(9.23)	(132,706)	(9.39)
Energy costs, net of realized FX hedge impact [1][2][4]	(78,180)	(5.49)	(74,355)	(5.26)
Transportation costs, net of realized FX hedge impact [1][2][5]	(155,789)	(12.00)	(147,780)	(11.80)
Operating Netback from Continuing Operations [1][2][6]	**343,983**	**32.51**	**437,991**	**41.27**
		(boe/d)		(boe/d)
Sales volumes, net of purchases [7]		32,813		31,988
Production Colombia [8]		39,011		38,623
Net production Colombia [9]		35,574		34,219

* Figures from 2024 reporting period were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

[1] Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.

[2] Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.

[3] Includes a gain of $2.6 million and $3.4 million from realized FX hedge attributable to production costs for the year ended December 31, 2025, and 2024, respectively. See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

[4] Includes a gain of $1.4 million and $1.3 million from realized FX hedge attributable to energy costs for the year ended December 31, 2025, and 2024, respectively. See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

[5] Includes a gain of $1.6 million and $1.0 million from realized FX hedge attributable to transportation costs for the year ended December 31, 2025, and 2024, respectively. See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

[6] 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

[7] Sales volumes, net of purchases, excluding sales of third-party volumes.

[8] Refer to the "Production Colombia" section on page 8 for further details.

[9] Refer to the "Further Disclosures" section on page 46 for further details.

Operating netback from continuing operations for the year ended December 31, 2025, was $32.51/boe compared to $41.27/boe in the same period of 2024. The changes were attributed to: (i) a 13% decrease in net sales realized prices; (ii) increased energy costs, net of realized FX hedge impact, due to higher energy use and fuel consumption associated with increased heavy crude oil production levels; (iii) increased transportation costs, mainly driven by the regular annual increase in transportation tariffs, partially offset by the optimization of transportation routes and pipeline agreements, including the termination of the long-term Ocensa P-135 take-or-pay agreement; and (iv) reduced production costs (excluding energy costs), net of realized FX hedge impact, primarily due to new field production technologies, continuous optimization, cost reduction in O&M contracts and digital process implementation.

Sales from Continuing Operations *

($M)	Three months ended December 31 2025	Three months ended December 31 2024	Year ended December 31 2025	Year ended December 31 2024
Produced crude oil sales	179,086	217,479	753,575	846,574
Purchased crude net margin [(1)(2)]	(7,007)	(11,552)	(37,311)	(38,118)
Conventional natural gas sales	4,959	1,591	11,280	7,537
Oil and gas sales, net of purchases [(3)]	177,038	207,518	727,544	815,993
(Loss) gain on oil price risk management contracts [(4)]	(1,186)	253	(8,680)	(8,457)
Royalties	(2,241)	(2,599)	(9,448)	(14,704)
Net sales [(3)]	**173,611**	**205,172**	**709,416**	**792,832**
Net sales realized price ($/boe) [(5)]	56.14	63.04	59.23	67.72

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.
(1) Corresponds to the net sales and costs of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes, as part of the Company's oil operations, marketing and transportation strategy.
(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.
(3) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.
(4) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 18 for further details.
(5) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.

Oil and gas sales, net of purchases, decreased by $30.5 million and $88.4 million for the three months and the year ended December 31, 2025, compared with the same periods of 2024, mainly due to a lower Brent benchmark oil price (refer to the "Realized and Reference Prices" section on page 10 for further details on price changes). The negative impact was partially offset by the additional volumes produced, improved oil price differentials and lower cash royalties.

Net sales for the three months and the year ended December 31, 2025, decreased by $31.6 million and $83.4 million, respectively, compared with the same periods of 2024. The following table describes the various factors that impacted net sales:

($M)	Three months ended December 31 2024 to 2025	Year ended December 31 2024 to 2025
Net sales for the period ended December 31, 2024	205,172	792,832
Decreased due to 10% lower oil and gas price (YTD 13% lower)	(21,148)	(104,788)
(Decreased) increased due to variance of total produced volumes sold	(9,332)	16,339
Decrease in royalties	358	5,256
Increase in oil price risk management contracts, net [(1)]	(1,439)	(223)
Net sales for the periods ended December 31, 2025	**173,611**	**709,416**

(1) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the "(Gain) Loss on Risk Management Contracts" section on page 18 for further details.

Oil and Gas Operating Costs from Continuing Operations *

($M)	Three months ended December 31 2025	Three months ended December 31 2024	Year ended December 31 2025	Year ended December 31 2024
Transportation costs	38,544	38,645	154,426	146,741
Production costs (excluding energy costs)	33,493	27,628	128,296	134,694
Energy costs	22,595	20,439	79,546	75,622
Post-termination costs	740	705	3,339	577
Trunkline costs and others	(652)	1,485	2,162	5,314
Inventory valuation	2,088	975	917	236
Total oil and gas operating costs	**96,808**	**89,877**	**368,686**	**363,184**

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

During the three months and the year ended December 31, 2025, total oil and gas operating costs increased by $6.9 million and $5.5 million, respectively, compared with the same periods of 2024. The variance in total oil and gas operating costs was mainly due to the following:

- For the three months ended December 31, 2025, transportation costs were in line with the same period of 2024, despite the regular annual increase in transportation tariffs, which was offset by the optimization of transportation routes and pipeline agreements, including the termination of the long-term Ocensa P-135 take-or-pay agreement. For the year ended December 31, 2025, transportation costs increased by 5% compared with the same period of 2024, primarily due to higher volumes produced and transported, and the regular annual increase in transportation tariffs.
- Production costs (excluding energy costs) for three months ended December 31, 2025, increased by 21% compared with the same period of 2024, primarily due to higher well services activity and the impact of the strong Colombian peso. For the year ended December 31, 2025, decreased by 5% compared with the same period of 2024, primarily due to new field production technologies, continuous optimization, cost reduction in O&M contracts and digital process implementation.
- Energy costs for the three months and the year ended December 31, 2025, increased by 11% and 5%, respectively, compared with the same periods of 2024, mainly due to increased fuel consumption resulting from higher processed production liquid volumes, higher heavy crude oil production levels during the year and the impact of the strong Colombian peso.
- Post-termination obligations for the three months and the year ended December 31, 2025, resulted in expenses of $0.7 million and $3.3 million, respectively, were primarily related to the relinquishment of production areas within the Cubiro block, and the Rio Ariari block in Colombia.
- Trunkline costs related to repairs and other activities undertaken in response to unexpected failures in a trunkline in the Quifa block, which have since been resolved, and an unforeseen crude oil incident in the CPE-6 block. The Company expects to recover a portion of these costs through claims under its property damage and liability insurance policies, which have already been submitted.
- Inventory valuation for the three months and the year ended December 31, 2025, increased by $1.1 million and $0.7 million, respectively, compared with the same periods of 2024, due to inventory drawdown.

Cost of Diluent and Oil Purchased

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Cost of diluent and oil purchased [1]	49,375	65,375	229,094	235,944

[1] This item is included in oil and gas sales, net of purchases. For further detail refer to the “Non-IFRS and Other Financial Measures” section on page 29 for further details.

Cost of diluent and oil purchased represents the cost of third-party hydrocarbon volumes purchased primarily for dilution and refining purposes as part of the Company’s oil operations, as well as its marketing and transportation strategy. For the three months and the year ended December 31, 2025, the cost of diluent and oil purchases decreased by $16.0 million and $6.9 million, respectively, compared with the same periods of 2024, mainly due to lower Brent benchmark oil prices, a new light crude oil optimization strategy for energy purposes, a heavy crude oil blend transported to Puerto Bahia, which requires less diluent, and increased local sales, partially offset by an increase in heavy oil production volumes.

Royalties *

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Royalties (all Colombia)	2,241	2,599	9,448	14,704

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 19 for further details.

Royalties include cash payments for PAP (as defined below), royalty payments, and payments to previous owners of certain blocks in Colombia. For the three months and the year ended December 31, 2025, royalties decreased by $0.4 million and $5.3 million, respectively, compared with the same periods of 2024, mainly due to a lower WTI oil benchmark price.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo, Casimena, and CPE-6 blocks. The ANH requires in-kind PAP payments for all blocks, except for the Guatiquia (Yatay field), Cubiro (Copa A field), and Casimena (Mantis field) blocks.

					Year ended December 31	
		Q4 2025	**Q3 2025**	**Q4 2024**	**2025**	**2024**
PAP in kind	(bbl/d)	224	330	668	406	1,424
PAP in cash	(bbl/d)	151	212	362	207	369
PAP	**(bbl/d)**	**375**	**542**	**1,030**	**613**	**1,793**
% Production		**1.0 %**	**1.4 %**	**2.5 %**	**1.6 %**	**4.6 %**

Depletion, Depreciation and Amortization *

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Depletion, depreciation and amortization	75,115	62,737	275,419	254,791

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

For the three months and the year ended December 31, 2025, depletion, depreciation, and amortization expense ("**DD&A**") increased by 20% and 8%, respectively, compared to the same periods of 2024, primarily due to higher production levels of heavy crude and the VIM-1 block, as well as additional depreciation associated from SAARA project's water treatment facilities.

Impairment Expense, Exploration Expenses and Others *

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Impairment expense of:				
Properties, plant and equipment				
North Colombia CGU	43,474	980	43,474	980
Central Colombia CGU	531,763	8,429	540,132	8,429
Infrastructure	13,021	350	13,021	350
Guyana	17,057	—	17,057	—
Impairment of properties plant and equipment	605,315	9,759	613,684	9,759
Exploration and evaluation assets				
Colombia	6,266	7,996	6,808	7,996
Guyana	250	—	432,757	—
Impairment of exploration and evaluation assets	6,516	7,996	439,565	7,996
Other	8,605	450	9,920	2,230
Total impairment	620,436	18,205	1,063,169	19,985
Exploration expenses of:				
Geological and geophysical costs, and other	441	415	1,848	1,613
Total exploration expenses	441	415	1,848	1,613
Expense of asset retirement obligations	1,691	(2,214)	5,500	2,335
Impairment expense, exploration expenses and other	622,568	16,406	1,070,517	23,933

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

The Company assesses at the end of each reporting period whether there are indicators, from both external and internal sources, that an asset or CGU may be impaired, or if there is any indication that previously recognized impairment losses may no longer exist or may have decreased. In performing the assessment, the Company considers changes in the market, economic and legal environments in which the Company operates that are beyond its control and that may affect the recoverable amount of its oil and gas, exploration and evaluation ("**E&E**") assets.

In consideration of the potential sale of the Frontera E&P Assets, the Company identified a change in the intended use of the assets related to the Colombian upstream business. Consequently, the recoverable amount was measured based on FVLCD, consistent with the value expected to be recovered in connection with the Parex Arrangement. For further details refer to the "Critical Judgments in Applying Accounting Policies" section on page 21 in the 2025 Annual Consolidated Financial Statements.

As a result, the carrying amounts as of December 31, 2025 of the assets related to the Colombian upstream business exceeded their recoverable amount. Accordingly, the Company determined that impairment charges of $591.6 million before tax should be recognized. This amount has been allocated between properties, plant and equipment and E&E asset's, as presented below.

The impairment generated by the change in the intended use of the assets related to the Colombian upstream business creates a temporary difference for deferred tax purposes. However, deferred tax assets are not recognized because, in accordance with paragraph 24 of IAS 12, they are not expected to be recovered in the future, considering the sale of the assets.

Properties, plant and equipment

During the year ended December 31, 2025, the Company recognized an impairment charge of $613.7 million (2024: $9.8 million). The impairment was mainly attributable to the change in the intended use of the assets related to the Colombian upstream business, totalling $585.4 million (for further information refer to "Critical Judgments in Applying Accounting Policies" section on page 21 in the 2025 Annual Consolidated Financial Statements).

The Company also recognized an impairment related to the Guyana port. The recoverable amount of the Port was determined based on VIU using a discounted cash flow model. Management determined that VIU was the most appropriate basis as there is no active market for comparable port infrastructure assets in the relevant jurisdiction. The discounted cash flow model is based on management-approved forecasts reflecting the current operating plan and expected utilization of the port facilities. Cash flows were projected over the remaining concession life through 2060. No terminal value was applied beyond the concession term.

The key assumptions used in the estimation of the Guyana Port included: pre-tax discount rate of 23%, forecast ramp-up of vessel traffic and throughput volumes consistent with current contractual and non-binding commercial discussions, operating cost structure reflecting current fixed and variable cost levels, capital expenditures limited to essential maintenance and committed infrastructure works and no significant expansion capex beyond currently supportable funding capacity. Based on these assumptions, the recoverable amount of the Guyana port was estimated at $2.2 million, resulting in an impairment charge of $17.1 million.

In addition, impairment charges were recognized in relation to Infrastructure assets and the relinquishment of certain fields or areas within the Cubiro and Corcel blocks.

Exploration and evaluation assets

During the year ended December 31, 2025, the Company recorded an impairment charge of $439.6 million (2024: $8.0 million), mainly related to the impairment of the Corentyne block in Guyana (for further information refer to the "Critical Judgments in Applying Accounting Policies" section on page 21). Additionally, an amount of $6.3 million was recognized in relation to the change in the intended use of the assets related to the Colombian upstream business. For further information refer to "Critical Judgments in Applying Accounting Policies" section on page 21 in the 2025 Annual Consolidated Financial Statements.

Other

During the year ended December 31, 2025, the Company recognized an impairment expense of $9.9 million, primarily related to Inventory and VAT in Peru, in addition to impairment attributable to obsolete inventory materials and certain accounts receivable (2024: $2.2 million).

Other Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
General and administrative	15,898	11,820	58,174	50,292
Special projects and other costs	4,469	3,029	17,031	9,870
Share-based compensation	1,063	827	3,520	2,514
Restructuring, severance, and other costs	2,279	2,096	21,084	5,312

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

General and Administrative ("G&A")

For the three months ended December 31, 2025, G&A expenses increased by 35% compared to the same period of 2024, mainly due to Colombian temporary taxes and lower overhead recovery. For the year ended December 31, 2025, G&A expenses increased 16%, compared to the same period of 2024, mainly due to Colombian temporary taxes of $7.2 million.

Special projects and other costs

For the three months and the year ended December 31, 2025, special projects and other costs increased by 48% and 73%, respectively, compared with the same periods of 2024, primarily due to SAARA's operating costs under the agreement with Ecopetrol, which was signed in June 2024.

Share-Based Compensation

For the three months and the year ended December 31, 2025, share-based compensation increased by $0.2 million and $1.0 million, respectively, compared to the same periods of 2024. The increase was due to a higher number of share units granted in 2025, partially offset by a lower stock price. Share-based compensation reflects cash and non-cash charges related to the vesting of restricted share units ("**RSUs**") and the granting of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability due to movements in the trading price of the Company's Common Shares.

Restructuring, Severance and Other Costs

For the three months and the year ended December 31, 2025, restructuring, severance and other costs increased by $0.2 million and $15.8 million, respectively, compared to the same periods of 2024. For the year 2025, this amount includes the simplification of its corporate structure, through targeted reorganization initiatives designed to improve organizational and operational efficiencies, in line with the Restructuring Plan (as defined below). Additionally, these costs include employee incentive payments, as well as fees and expenses related to the recapitalization of the Company's interest in the ODL pipeline.

Non-Operating Costs *

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Finance income	1,392	1,851	6,677	8,363
Finance expenses	(18,888)	(21,473)	(71,333)	(73,252)
Foreign exchange loss	(4,357)	(1,795)	(2,595)	(11,041)
Other (income) loss	(6,359)	6,696	7,008	(672)

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

Finance Income

For the three months and the year ended December 31, 2025, finance income decreased by $0.5 million and $1.7 million, respectively, compared with the same periods of 2024, mainly due to changes in interest rates and balances on investment trust accounts related to abandonment requirements.

Finance Expenses

For the three months and the year ended December 31, 2025, finance expenses decreased by $2.6 million and $1.9 million, respectively, compared with the same periods of 2024, mainly due to lower accretion expenses of asset retirement obligations, lower interest expenses related to 2028 Unsecured Notes (as defined below), partially offset by additional interest resulting from the FPI Recapitalization Loan (as defined below).

Foreign Exchange Loss

For the three months ended December 31, 2025, the Company recognized foreign exchange loss of $4.4 million, compared to loss of $1.8 million for the same period of 2024, mainly due to transfer from the cumulative translation adjustment within Other Comprehensive Income to the Consolidated Statement of Income of a return of capital of ODL.

For the year ended December 31, 2025, the Company recognized foreign exchange loss of $2.6 million compared to loss of $11.0 million for the same period of 2024. The lower foreign exchange loss was primarily due to the appreciation of the COP against the USD during 2025, compared to a depreciation of the COP against the USD during 2024. These exchange rate movements impacted the Company's net working capital balances denominated in COP. Foreign exchange rates (COP:USD) as at December 31, 2025, and December 31, 2024, were 3,757.08:1 and 4,409.15:1, respectively.

Other (Income) Loss

For the three months ended December 31, 2025, the Company recognized other loss of $6.4 million, primarily due to changes in contingencies. In contrast, for the same period of 2024, the Company recognized other income of $6.7 million, mainly attributable to the net of reversal and new contingencies.

For the year ended December 31, 2025, the Company recognized other income of $7.0 million, mainly related to insurance recoveries for the Sabanero block of $14.7 million, partially offset by losses associated with the recognition of contingencies. For the same period of 2024, the Company recognized other loss of $0.7 million, primarily due to contingencies partially offset by income related to insurance compensation for the Sabanero block during the first quarter of 2024.

Gain (Loss) on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
(Loss) gain on oil price risk management contracts [1]	(1,186)	253	(8,680)	(8,457)
Realized gain on foreign exchange risk hedge [2]	2,184	921	4,204	6,951
Realized gain (loss) on risk management contracts	998	1,174	(4,476)	(1,506)
Unrealized gain (loss) on risk management contracts	2,306	(10,035)	7,518	(13,976)
Total gain (loss) on risk management contracts	3,304	(8,861)	3,042	(15,482)

[1] Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period.

[2] For determination of operating netback from continuing operations, during the three months and the year ended December 31, 2025, the Company estimates an attribution of $1.4 million and $2.6 million, respectively, of the total realized FX hedge to production cost (excluding energy cost) (2024: $Nil and $3.4 million respectively), estimates an attribution of $0.7 million and $1.4 million, respectively, of the total realized FX hedge to energy (2024: $Nil and $1.3 million, respectively), and estimates an attribution of $0.8 million and $1.6 million, respectively, of the total realized FX hedge to transportation (2024: $Nil and $1.0 million), respectively. Refer to the "Non-IFRS and Other Financial Measures" section on page 29.

For the three months and the year ended December 31, 2025, the realized gain of $1.0 million and the loss of $4.5 million, respectively, on risk management contracts was mainly due to: (i) a loss of $1.2 million and $8.7 million, respectively, on oil price risk management contracts, resulting from a net amount of the put premiums paid for expired positions of $3.8 million and $18.4 million, respectively, mitigated in part by the positive cash settlement of $2.6 million and $9.7 million, respectively; and partially offset by (ii) a gain of $2.2 million and $4.2 million, respectively, on the cash settlement of risk management contracts of foreign exchange currency. In comparison, for the three months ended December 31, 2024, the realized gain on risk management contracts was $1.2 million, resulting from (i) $0.3 million net of the positive cash settlement of $4.0 million from oil price contracts during the period partially offset by the put premiums paid for expired positions of $3.7 million and (ii) $0.9 million positive cash settlement on derivatives resulting from the FPI Loan Facility (as defined below). During the year ended December 31, 2024, the realized loss on risk management contracts was $1.5 million, resulting from; (i) a loss of $8.5 million, due to the net of the put premiums paid for expired positions of $14.5 million and the positive cash settlement received of $6.1 million from oil price contracts during the period, and partially offset by (ii) a gain of $7.0 million from the cash settlement of foreign exchange risk management contracts.

For the three months and the year ended December 31, 2025, risk management contracts had an unrealized gain of $2.3 million and $7.5 million, respectively, compared to a loss of $10.0 million and $14.0 million, respectively, in the same periods of 2024, primarily due to mark to market variances from foreign exchange risk management contracts and changes in the benchmark forward prices of Brent.

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. The Company's strategy aims to protect a minimum of 40% of estimated production with a tactical approach, using derivative commodity instruments to protect the Company's revenue generation and cash position, while maximizing the upside.

				Avg. Strike Prices	Carrying Amount	
Type of Instrument	**Term**	**Benchmark**	**Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put Spread	March 2026 - June 2026	Brent	1,529,200	62.7x55	767	—
Put Spread	January 2026 to March 2026	Brent	1,107,000	65/55	1,948	
Total as at December 31, 2025			2,636,200		2,715	—

Subsequent to the end of the quarter, the Company has not entered into any new hedges.

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. This exposure arises primarily due to expenditures incurred in COP and the fluctuation of this currency against the USD. In addition, during 2025, the Company entered into new derivative contracts associated with the collection of dividends from ODL, as required under the FPI Recapitalization Loan (as defined below).

As at December 31, 2025, the Company did not have any foreign currency derivatives contracts. In addition, subsequent to the end of the quarter, the Company has not entered into any new hedges.

Income Tax

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Current income tax recovery (expense)	6,685	821	(46)	(7,029)
Deferred income tax (expense) recovery	(28,207)	(36,415)	22,603	(92,295)
Total income tax (expense) recovery from continuing operations	(21,522)	(35,594)	22,557	(99,324)

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

For the three months and the year ended December 31, 2025, the Company recognized a current income tax recovery of $6.7 million and a current income tax expense of $46.0 thousand, respectively, compared to a current income tax recovery of $0.8 million and a current income tax expense of $7.0 million, respectively, in the same periods of 2024. Additionally, the Company recognized a deferred income tax expense of $28.2 million and recovery of $22.6 million, compared with a deferred income tax expense of $36.4 million and $92.3 million, respectively, in the same periods of 2024. The variance in deferred tax was mainly due to the reversal of deferred tax liabilities recorded in 2024. As of December 31, 2025, no deferred tax assets were recognized in respect of Frontera's Colombian oil and gas exploration and production assets, as recoverability was not considered probable following the announcements made on January 30, 2026 and March 10, 2026 and the execution of the Parex Arrangement Agreement (for further information, refer to the "Critical Judgments in Applying Accounting Policies" section on page 21 of the 2025 Annual Consolidated Financial Statements).

Discontinued Operations

On July 31, 2025, the Company entered into an agreement for the disposal of its 50% working interest in the Perico and Espejo blocks in Ecuador to Gran Tierra Energy Inc., for a total cash consideration of $7.8 million. The consideration was subject to working capital and other customary adjustments as of the effective date of January 1, 2025. The agreement also included a contingent consideration arrangement for an additional $0.8 million, which was payable to the Company upon the Perico block having reached cumulative gross production of two million barrels from January 1, 2025 onward. After receiving government approval on November 25, 2025, and ultimately upon execution of a public deed on December 9, 2025, the transaction was fully completed.

As a result, the Company recognized a loss related to remeasurement to fair value less costs to sell of $5.4 million.

The results of the discontinued operations for the three months and the year ended December 31, 2025 and 2024 are presented below:

	Three months ended December 31		Year ended December 31	
(In thousands of U.S.$, except per share information)	**2025**	**2024**	**2025**	**2024**
Revenue	1,113	7,834	17,588	29,132
Operating costs	631	2,626	7,231	7,938
General and administrative	228	1,350	804	2,081
Share-based compensation	(10)	8	(8)	41
Impairment, and depletion, depreciation and amortization	6	14,453	49,634	19,668
Income (loss) from operations from discontinued operations	258	(10,603)	(40,073)	(596)
Finance expense, net	(91)	(336)	(301)	(930)
Other (loss) income	(19)	(171)	405	(228)
Net income (loss) before income tax from discontinued operations	148	(11,110)	(39,969)	(1,754)
Income tax (expense) recovery	(286)	2,194	3,048	(3,780)
Related to remeasurement to fair value less costs to sell	3,043	—	(5,438)	—
Net income (loss) for the period from discontinued operations	$ 2,905	(8,916)	$ (42,359)	$ (5,534)

Net (Loss) Income from Continuing Operations and Discontinued Operations

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Net loss for the period from continuing operations [(1)]	(663,354)	(20,485)	(1,020,361)	(18,628)
Net income (loss) for the period from discontinued operations [(1)]	2,905	(8,916)	(42,359)	(5,534)
Net loss for the period [(1)]	(660,449)	(29,401)	(1,062,720)	(24,162)
Per share – basic from continuing operations ($)	(9.51)	(0.25)	(13.77)	(0.22)
Per share – diluted from continuing operations ($)	(9.51)	(0.25)	(13.77)	(0.22)
Per share – basic from discontinued operations ($)	0.04	(0.11)	(0.57)	(0.07)
Per share – from discontinued operations diluted ($)	0.04	(0.11)	(0.57)	(0.07)

[(1)] (Loss) income attributable to equity holders of the Company.

During the fourth quarter of 2025, the Company reported net loss from continuing operations, attributable to equity holders of the Company, of $663.4 million mainly resulting from a loss from operations of $636.6 million (net of a non-cash impairment expense of $620.4 million), an income tax expense of $21.5 million (including $28.2 million of deferred income tax expenses), finance expenses of $18.9 million and foreign exchange loss of $4.4 million, partially offset by $14.1 million from share of income from associates, $3.3 million related to income on risk management contracts and $1.4 million of finance income. This compares with net loss from continuing operations, attributable to equity holders of the Company, in the fourth quarter of 2024, of $20.5 million, which included an income tax expense of $35.6 million (including $36.4 million of deferred income tax expenses), finance expenses of $21.5 million, $8.9 million related to loss on risk management contracts, and foreign exchange loss of $1.8 million, partially offset by income from operations of $25.5 million (net of a non cash impairment expense of $18.2 million) and $13.2 million from the share of income from associates.

For the year ended December 31, 2025, the Company reported a net loss from continuing operations, attributable to equity holders of the Company, of $1,020.4 million, mainly resulting from a loss from operations of $1,070.4 million (net of a non-cash impairment expense of $1,063.2 million) and finance expenses of $71.3 million, partially offset by $59.2 million from share of income from associates, an income tax recovery of $22.6 million (including $22.6 million of deferred income tax recovery), other income by $7.0 million mainly related to insurance recoveries for the Sabanero block of $14.7 million, $13.3 million of gain on the repurchase of the 2028 Senior Unsecured Notes, net of the consent solicitation, and finance income of $6.7 million. This is compared to a net loss from continuing operations, attributable to equity holders of the Company, in the year ended of 2024, of $18.6 million, which included an income tax expense of $99.3 million (including $92.3 million of deferred income tax expenses), finance expenses of $73.3 million, $15.5 million related to loss on risk management contracts and $11.0 million of foreign exchange loss, partially offset by operating income of $117.3 million (net of a non cash impairment expense of $20.0 million) and $53.9 million from share of income from associates.

Capital Expenditures and Acquisitions *

	Three months ended December 31		Year ended December 31	
($M)	2025	2024	2025	2024
Development drilling	12,998	5,817	96,670	98,643
Development facilities	20,057	34,900	62,526	98,043
Colombia exploration	16,416	5,861	31,015	16,957
Other	855	11,396	2,747	25,892
Total Colombia upstream capital expenditures	**50,326**	**57,974**	**192,958**	**239,535**
Colombia infrastructure	2,828	25,999	15,706	47,882
Guyana exploration	93	571	529	3,267
Total capital expenditures from continuing operations (1)	**53,247**	**84,544**	**209,193**	**290,684**
Exploration and development in Ecuador	—	1,322	1,604	27,173
Total capital expenditures from discontinued operations (2)	**—**	**1,322**	**1,604**	**27,173**

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador.

(1) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.

(2) The Company agreed on July 31, 2025, to sell its 50% interest in the Perico and Espejo blocks located in Ecuador. After receiving government approval on November 25, 2025, and ultimately upon execution of a public deed on December 9, 2025, the transaction was fully completed. Refer to the "Discontinued Operations" section on page 19 for further details.

Capital expenditures for the three months and the year ended December 31, 2025, were $53.2 million and $209.2 million respectively, compared with $84.5 million and $290.7 million respectively, in the same periods of 2024, as follows:

Development drilling. During the three months and the year ended December 31, 2025, development drilling expenditures were $13.0 million and $96.7 million, respectively, compared with $5.8 million and $98.6 million respectively, for the same periods of 2024. No development wells were drilled in the fourth quarter of 2025, however, 3 development wells were spudded before year end 2025. In the same period of 2024, 2 development wells were drilled in the Sabanero block. For the year ended December 31, 2025, 55 development wells (including two injector wells) were drilled mainly in the Quifa and CPE-6 blocks, in Colombia, while in the same period of 2024 a total of 65 development wells (including two injector wells) were drilled in the Quifa, CPE-6 and Sabanero blocks.

Development facilities. During the three months and the year ended December 31, 2025, development facility expenditures were $20.1 million and $62.5 million, respectively, primarily related to facility expansion and the installation of new and improved flow lines in the Cajua field, within the Quifa block, to support new well production and the SAARA connection. Additionally, expenditures were made to expand crude oil storage capacity and improve roads in the CPE-6 block. For the same periods of 2024, development facility expenditures were $34.9 million and $98.0 million, respectively, mainly related to the increase of water-handling capacity at the CPE-6 block, new and improved flow lines in the Quifa Block to integrate with the SAARA project, and expansion of gas compression facilities in the VIM-1 block.

Colombia Exploration. During the three months and the year ended December 31, 2025, expenditures related to exploration activities were $16.4 million and $31.0 million, respectively, compared with $5.9 million and $17.0 million, respectively, in the same periods of 2024. During the fourth quarter of 2025, the Company's exploration focus remained on the Lower Magdalena Valley and Llanos Basins in Colombia. At the VIM-1 block, Guapo-1 exploration well was spudded on October 16, 2025, and reached total depth, approximately 15,000 feet, on December 31, 2025. Following logging operations, it was determined that hydrocarbon production was not commercial. Parex and Frontera have agreed to proceed with plugging and abandoning the well. In addition, the Company is engaged in pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-99 and VIM-46 blocks to ensure the drilling of exploratory wells from 2026 onward. At the Llanos-99 block, the operational phase of the 3D seismic survey has commenced with the mobilization of materials and equipment.

Other. Other capital expenditures for the three months and the year ended December 31, 2025, were $0.9 million and $2.7 million, respectively. These expenditures were primarily related to the implementation of new field production technologies at the Quifa and CPE-6 blocks. The expenditures for the same periods of 2024, were mainly related to generation energy facilities funded primarily through the reimbursement of insurance claim related to the Sabanero block.

Colombia infrastructure. Capital expenditures for the three months and the year ended December 31, 2025, were $2.8 million and $15.7 million, respectively, compared with $26.0 million and $47.9 million, respectively, for the same periods of 2024. During the fourth quarter of 2025, investments totaling $1.7 million were made in Puerto Bahia, including: (i) $0.9 million in investment towards the connection project between Puerto Bahia's port facility and the Cartagena refinery, effectively completed, pursuant to the connection agreement between Puerto Bahia and Refinería de Cartagena S.A.S. ("**Reficar**"), (ii) tank maintenance, and (iii) general expenditures related to the cargo terminal facilities. Fourth quarter capital expenditures also includes investment in the SAARA project and palm oil plantation. During the same periods of 2024, capital expenditures included investments in the Puerto Bahia and SAARA project.

Guyana exploration. During the three months and the year ended December 31, 2025, Guyana exploration expenditures were $0.1 million and $0.5 million, respectively, compared to $0.6 million and $3.3 million, respectively during the same periods of 2024. These expenditures were associated with other capitalized costs.

Selected Quarterly Information *

Operational and financial results from Continuing Operations		2025 Q4	2025 Q3	2025 Q2	2025 Q1	2024 Q4	2024 Q3	2024 Q2	2024 Q1
Heavy crude oil production	(bbl/d)	26,696	27,078	27,535	27,167	27,740	25,312	24,839	23,398
Light and medium crude oil combined production	(bbl/d)	8,918	9,235	9,850	9,531	10,484	11,018	10,928	11,102
Total crude oil production	(bbl/d)	35,614	36,313	37,385	36,698	38,224	36,330	35,767	34,500
Conventional natural gas production	(mcf/d)	5,261	4,406	3,118	2,274	2,633	3,192	4,019	3,283
Natural gas liquids production	(boe/d)	1,795	1,848	1,846	1,913	1,970	1,950	1,785	1,639
Total production Colombia	(boe/d)	38,332	38,934	39,778	39,010	40,656	38,840	38,257	36,715
Sales volumes, net of purchases	(boe/d)	33,612	34,205	30,537	32,873	35,376	32,670	29,953	29,910
Brent price reference	($/bbl)	63.08	68.17	66.71	74.98	74.01	78.71	85.03	81.76
Oil and gas sales, net of purchases (1)(2)	($/boe)	57.25	61.70	59.53	64.53	63.76	67.54	75.75	73.10
Gain (loss) on oil price risk management contracts (3)(4)	($/boe)	(0.38)	(1.20)	0.16	(1.40)	0.08	(0.47)	(1.39)	(1.28)
Royalties (3)	($/boe)	(0.73)	(0.78)	(0.71)	(0.94)	(0.80)	(0.80)	(1.94)	(1.61)
Net sales realized price (1)(2)	($/boe)	56.14	59.72	58.98	62.19	63.04	66.27	72.42	70.21
Production costs (excluding energy costs), net of realized FX hedge impact (2)(3)	($/boe)	(9.64)	(8.46)	(8.89)	(9.96)	(7.60)	(8.89)	(10.93)	(10.31)
Energy costs, net of realized FX hedge impact (3)	($/boe)	(6.22)	(5.56)	(4.75)	(5.46)	(5.46)	(5.25)	(4.88)	(5.45)
Transportation costs, net of realized FX hedge impact (2)(3)	($/boe)	(11.92)	(11.72)	(11.81)	(12.55)	(11.59)	(12.59)	(11.30)	(11.71)
Operating netback from continuing operations per boe (1)(2)	($/boe)	28.36	33.98	33.53	34.22	38.39	39.54	45.31	42.74
Revenue	($M)	238,478	257,252	234,722	268,272	282,780	269,036	269,352	263,487
Net (loss) income for the period from continuing operations	($M)	(663,354)	28,235	(410,857)	25,615	(20,485)	16,923	(6,310)	(8,756)
Per share – basic from continuing operations ($)	($)	(9.51)	0.40	(5.32)	0.33	(0.25)	0.20	(0.07)	(0.10)
Per share – diluted from continuing operations ($)	($)	(9.51)	0.38	(5.32)	0.31	(0.25)	0.19	(0.07)	(0.10)
General and administrative	($M)	15,898	14,877	14,021	13,378	11,820	12,473	12,682	13,317
Operating EBITDA from Continuing Operations (5)	($M)	68,907	86,585	73,489	79,048	109,620	96,494	102,776	96,228
Capital expenditures (5)	($M)	53,247	50,859	58,967	46,120	84,544	74,872	72,671	58,597

* Figures for the Q1 and Q2 2025, and 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 19 for further details.

(1) Non-IFRS ratio. Refer to the “Non-IFRS and Other Financial Measures'' section on page 29 for further details.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Supplementary financial measure. Refer to the “Non-IFRS and Other Financial Measures'' section on page 29 for further details.

(4) Includes the net effect of put premiums paid for expired positions and positive cash settlements received from oil price contracts during the period. Refer to the “Gain (Loss) on Risk Management Contracts” section on page 18 for further details.

(5) Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures” section on page 29 for further details.

Over the past eight quarters, the Company’s sales have experienced fluctuations driven by variations in production levels, movements in Brent oil benchmark prices, the timing of cargo shipments, and changes in crude oil price differentials. Since 2024, production has been increased mainly due to: (i) an increase in heavy crude oil production, driven by successful development drilling campaigns in the Quifa, CPE-6, and Sabanero blocks, the new water-handling facilities in the CPE-6 block, the reactivation of wells in the Sabanero block, and increased processing capacity at SAARA, (ii) natural gas liquids production fluctuated due to natural decline and development in the VIM-1 block; and (iii) Variances in conventional natural gas production due to natural decline and the development of facilities for surface gas compression and handling systems at VIM-1 block. These increases were partially offset by a decrease in light and medium crude oil combined production mainly due to natural decline.

Production costs (excluding energy costs) fluctuated, with reduction during the quarters of 2025 specially, primarily due to new field production technologies, continuous optimization, cost reduction in O&M contracts and digital process implementation. partially offset by inflationary pressures on services, wage indexation, well services and maintenance activities. Transportation costs have also fluctuated mainly due to the regular annual increase in transportation tariffs, as well as changes in barrels produced and transported, and occasional changes in wellhead sales. In addition, energy costs fluctuated in line with market prices and increase in heavy oil production.

Trends in the Company's net (loss) income from continuing operations, attributable to equity holders of the Company, are primarily impacted by the recognition and derecognition of deferred income taxes, the recognition of impairment charges related to exploration and evaluation, and oil and gas assets, DD&A, foreign exchange gains or losses, and gains or losses from risk management contracts, which fluctuate mainly with changes in hedging strategies, crude oil benchmark forward prices and appreciation or devaluation of the COP against the USD. Please refer to the Company's previously filed annual and interim Management's Discussion and Analysis, available on SEDAR+ at www.sedarplus.ca, for further information regarding changes in prior quarters.

Selected Annual Information

	As at and for the year ended December 31		
($M, except as noted)	**2025**	**2024**	**2023**
Revenue	998,724	1,084,655	1,148,603
Net (loss) income for the period from continuing operations [1]	(1,020,361)	(18,628)	193,497
Per share – basic ($)	(13.77)	(0.22)	2.27
Per share – diluted ($)	(13.77)	(0.22)	2.19
Cash and cash equivalents	230,489	192,577	159,673
Total assets	1,831,732	2,900,877	3,016,280
Total non-current liabilities	687,759	661,129	637,586
Total liabilities	1,239,145	1,174,744	1,182,287

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. However, figures from 2023 have not been adjusted and include the results of operations for the non-core Ecuador assets. Refer to the "Discontinued Operations" section on page 19 for further details.

[1] Refers to net (loss) income attributable to equity holders of the Company.

Revenue decreased to $1.00 billion in 2025 from $1.08 billion in 2024, and from $1.15 billion in 2023. The revenue decrease was primarily due to fluctuations in Brent benchmark oil prices and variance of total produced volumes sold.

Net (loss) income for the period from continuing operations, attributable to equity holders of the Company, for 2025 was a loss of $1,020.4 million, compared to a loss of $18.6 million in 2024, and an income of $193.5 million in 2023, mainly as a result of lower income from operations, impacted by the non-cash impairment of exploration and evaluation assets and oil and gas assets during 2025 and 2024, as well as the recognition and derecognition of deferred income taxes.

Total assets decreased to $1.83 billion in 2025, compared with $2.90 billion in 2024 and $3.02 billion in 2023, mainly due to the impairment attributable to the change in the intended use of the assets related to the Colombian upstream business and the impairment of exploration and evaluation assets related to the Corentyne block in Guyana.

Cash and cash equivalents increased to $230.5 million in 2025, from $192.6 million in 2024 and $159.7 million in 2023, mainly due to a prepayment under commercial agreement with Chevron, through which the Company received an advance of $80 million at the end of 2025. In 2023, cash and cash equivalents were lower due to exploration investment activities, particularly in Guyana during that year.

Infrastructure Colombia

Frontera has investments in certain infrastructure, midstream, and other assets, including storage facilities, a port, a reverse osmosis water treatment facility, a palm oil plantation, other facilities in Colombia, and the Company's investment in pipelines (together referred to as the "**Infrastructure Colombia Segment**").

As part of the Parex Arrangement Agreement, Frontera is selling the SAARA and ProAgrollanos assets, given their close operational linkage to supporting activities in the Quifa block. Following the closing of the Parex Arrangement Agreement, Frontera's Infrastructure Colombia business will no longer include SAARA or ProAgrollanos.

The Company's Infrastructure Colombia Segment includes the following:

Asset	Description	Interest [1]	Accounting Method
Puerto Bahia	Bulk liquids storage and import-export terminal, and bidirectional hydrocarbon flow line connecting port facility and the Cartagena refinery.	99.97% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline with capacity of 300,000 bbl/d	100% interest in FPI (which holds a 35% interest in ODL)	Equity method [2]
SAARA [3]	Reverse osmosis water treatment facility with nameplate capacity of 1,000,000 bwpd	100% interest in Agro Cascada	Consolidation
ProAgrollanos	Palm oil plantation with production capacity 28,000-33,000 tons per year of fresh fruit bunches	100% interest in Promotora Agricola de los Llanos S.A ("**ProAgrollanos**")	Consolidation

[1] Interests include both direct and indirect holdings.

[2] Equity method accounting requires that the carrying value of the investment be increased to reflect the Company's proportionate share of net income, or reduced to reflect its share of net losses and dividends declared.

[3] SAARA is a project implemented by Agro Cascada S.A.S. ("**Agro Cascada**").

Performance Highlights

					Year ended December 31	
		Q4 2025	Q3 2025	Q4 2024	2025	2024
Operational and IFRS Results						
Volumes pumped at oil pipeline facility	(bbl/d)	241,734	241,958	235,528	238,994	243,669
Volume throughput at port liquids facility	(bbl/d)	40,548	39,560	61,990	46,193	56,020
Volumes handled at RORO port general cargo facility	(Units)	38,727	36,303	21,676	121,536	74,425
Break Bulk Volumes at port	(Tons/m3)	15,406	9,426	34,690	73,568	69,494
Volumes of water received in SAARA from production fields	(bwpd)	181,637	156,767	78,716	135,158	44,121
Production of fresh fruit bunches	(Tons)	7,191	6,214	6,183	28,128	25,357
Infrastructure Colombia Segment (loss) income	($M)	(4,144)	15,544	15,183	40,974	55,477
Infrastructure Colombia Segment cash flow from operating activities	($M)	12,570	22,062	14,788	61,806	58,032
Non IFRS Results [1]						
Adjusted Infrastructure Revenues	($M)	51,984	49,172	45,278	191,037	171,392
Adjusted Infrastructure EBITDA	($M)	30,541	30,444	27,532	116,645	107,223
Adjusted Infrastructure Cash	($M)	34,841	67,811	72,423	34,841	72,423
Adjusted Infrastructure Debt	($M)	180,968	223,216	116,895	180,968	116,895
Capital Expenditures Infrastructure Colombia Segment	($M)	2,828	5,344	25,999	15,706	47,882

[1] Non-IFRS financial measures (equivalent to "non-GAAP financial measures", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 29 for further details.

Infrastructure Colombia Segment Results

The Interim Financial Statements include the following amounts related to the Infrastructure Colombia Segment:

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Revenue	17,065	13,873	60,055	48,542
Costs	(12,007)	(8,099)	(42,674)	(31,438)
General and administrative expenses	(1,537)	(1,507)	(5,653)	(5,903)
Depreciation, amortization and impairment expense	(20,326)	(1,872)	(27,212)	(7,926)
Other operating costs	(1,446)	(412)	(2,739)	(1,710)
Infrastructure Colombia (loss) income from operations	**(18,251)**	**1,983**	**(18,223)**	**1,565**
Share of income from associates - ODL	14,107	13,200	59,197	53,912
Infrastructure Colombia Segment (loss) income	**(4,144)**	**15,183**	**40,974**	**55,477**
Infrastructure Colombia Segment cash flow from operating activities	12,570	14,788	61,806	58,034
Capital Expenditures Infrastructure Colombia Segment [1]	2,828	25,999	15,706	47,882

[1] Non-IFRS financial measures (equivalent to a “non-GAAP financial measures”, as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures’’ section on page 29 for further details.

In the Company’s Infrastructure Colombia Segment, results for the three months ended December 31, 2025, changed from income of $15.2 million to a loss of $4.1 million. For the year ended December 31, 2025, segment income decreased by 26% compared with the same period in 2024. These variation were mainly due to non-cash depreciation, amortization and impairment expense of $27.2 million, recognized in fourth quarter 2025 and, higher operating costs in SAARA project, partially offset by the share of income from ODL, driven by higher revenues resulting from a 7.8% increase in pipeline transportation tariffs implemented in September 2024, and higher general cargo revenue at Puerto Bahia’s port.

Segment capital expenditures for the three months and the year ended December 31, 2025, were $2.8 million and $15.7 million, respectively, compared with $26.0 million and $47.9 million, respectively, for the same periods of 2024. During the fourth quarter of 2025, investments totaling $1.7 million were made in Puerto Bahia, including: (i) $0.9 million towards the connection project between Puerto Bahia’s port facility and the Cartagena refinery, (ii) tank maintenance, and (iii) general expenditures related to the cargo terminal facilities. Fourth quarter capital expenditures also includes investment in the SAARA project and palm oil plantation. During the same periods of 2024, capital expenditures included investments in the Puerto Bahia and SAARA project.

ODL Pipeline

The Company, through its 100%-owned subsidiary FPI, has a 35% equity investment in the ODL pipeline, which connects Rubiales, Quifa, Caño Sur, Llanos-34, and other blocks to the Monterrey and Cusiana Stations in the department of Casanare.

For the three months and the year ended December 31, 2025, ODL generated an EBITDA of $77.2 million and $299.8 million, respectively, and net income of $40.3 million and $169.1 million, respectively. The ODL results are consolidated through the equity method in the 2025 Annual Consolidated Financial Statements as “Share of income from associates”.

The income statement and key balance sheet information for 100% of ODL is as follows:

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Revenue	99,769	89,728	374,235	351,000
FEC revenue (billed units)	8,067	7,573	31,131	29,608
Third party revenues	91,702	82,155	343,104	321,392
Costs	(16,753)	(16,270)	(54,684)	(54,020)
General administrative expenses	(5,814)	(6,985)	(19,788)	(22,628)
Depreciation, amortization and impairment expense	(9,410)	(6,855)	(31,726)	(30,866)
Other non-operating expense	(3,961)	(1,424)	(7,021)	(6,337)
Income tax	(23,526)	(20,479)	(91,884)	(83,113)
ODL Net Income	**40,305**	**37,715**	**169,132**	**154,036**

($M)	December 31 2025	December 31 2024
ODL debt	39,382	36,954
ODL cash and cash equivalents	53,594	76,979

The following table shows the volumes pumped per injection point:

	Three months ended December 31		Year ended December 31	
(bbl/d)	2025	2024	2025	2024
At Rubiales Station	133,831	167,272	142,747	169,890
At Caño Sur Station	50,266	—	36,412	—
At Jagüey and Palmeras Stations	57,637	68,256	59,835	73,779
Total	**241,734**	**235,528**	**238,994**	**243,669**

The following table shows the volumes received per block:

	Three months ended December 31		Year ended December 31	
(bbl/d)	2025	2024	2025	2024
Rubiales	94,073	100,604	95,758	102,794
Caño Sur	50,266	31,044	45,452	29,486
Quifa	29,721	28,384	29,613	28,800
CPE-6 and Sabanero	1,002	1,501	1,084	2,405
Other blocks	57,638	58,772	60,016	65,090
Total	**232,700**	**220,305**	**231,923**	**228,575**

For the three months and the year ended December 31, 2025, the Company recognized $14.1 million and $59.2 million, respectively, as its share of income from ODL, which was higher than the same periods of 2024 by $13.2 million and $53.9 million respectively. This result was driven by higher revenues, primarily due to a 7.8% increase in pipeline transportation tariffs implemented in September 2024, partially offset by lower volumes pumped for the year 2025. For the fourth quarter 2025, the Company received higher volumes, driven by additional production associated with Ecopetrol's Caño Sur block.

During the three months and the year ended December 31, 2025, ODL declared net dividends to FPI of $Nil and $57.3 million, respectively (2024: $Nil and $54.9 million respectively), and a return of capital of $4.6 million and $4.6 million, respectively (2024: $Nil and $7.9 million, respectively). During the three months and the year ended December 31, 2025, FPI received cash of $16.9 million and $61.6 million, respectively, in dividends and return of capital from ODL (2024: $16.9 million and $60.3 million, respectively in dividends and return of capital from ODL).

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia, which consists of a hydrocarbons terminal and a general cargo terminal adjacent to the Bocachica access channel in the Cartagena Bay. It is strategically located near the Cartagena refinery operated by Reficar. The port facility has a total area of 150 hectares. Puerto Bahia's income from operations is mainly generated from service contracts in the liquids terminal, which has a nominal capacity of 2,672,000 barrels, and from roll-on/roll-off (RORO), break bulk and containers services in the general cargo terminal.

	Three months ended December 31		Year ended December 31	
($M)	2025	2024	2025	2024
Revenue	12,755	11,502	45,747	42,162
Liquids port facility	5,623	7,726	24,582	29,425
FEC liquids port facility	1,660	1,152	5,223	6,972
Third party liquids port facility	3,963	6,574	19,359	22,453
General cargo	7,132	3,776	21,165	12,737
Costs	(7,539)	(5,088)	(25,643)	(21,558)
General and administrative expenses	(1,306)	(1,390)	(4,969)	(5,427)
Depreciation, amortization and impairment expense	(9,835)	(1,652)	(14,931)	(7,154)
Restructuring, severance and other costs	(1,446)	(412)	(2,739)	(1,710)
Puerto Bahia Operating (loss) Income	(7,371)	2,960	(2,535)	6,313
Puerto Bahia EBITDA	**3,910**	**5,024**	**15,135**	**15,177**

The following table shows throughput for the liquids port facility at Puerto Bahia:

(bbl/d)	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
FEC volumes	12,587	11,626	10,555	13,513
Third party volumes	27,961	50,364	35,639	42,506
Total	**40,548**	**61,990**	**46,194**	**56,019**

The following table shows the RORO units, their dwell times, the containers and break bulk volumes, for the general cargo port facility at Puerto Bahia:

		Three months ended December 31		Year ended December 31	
		2025	2024	2025	2024
RORO	Units [1]	38,727	21,676	121,536	74,425
	Dwell time in days [2]	34	48	31	54
Containers	TEUs [3]	6,436	539	17,890	1,003
Break Bulk Volumes	Tons/m^3 [4]	15,406	34,690	73,568	69,494

(1) Wheeled cargo, primarily cars imported to Colombia.

(2) Dwell time refers to the time spent by the units within the general cargo port facility. The variance in dwell time associated with Break Bulk Volumes could depend on the characteristics of the cargo, especially in situations where the cargo is received and dispatched within a single day.

(3) Twenty-foot Equivalent Unit.

(4) Other types of cargo other than wheeled cargo and containers.

For the three months and the year ended December 31, 2025, Puerto Bahia's general cargo revenues increased by 89% and 66%, respectively, mainly due to a strong performance in the dry port, which saw significant growth in container volumes and higher volumes handled in RoRo units. In contrast, lower third party liquids volumes reflected reduced throughput from key customers and the absence of certain trading flows.

Frontera together with its partner GASCO, announced that the planned LPG project has been approved for development. The initial phase of the project is being fast-tracked and expected to be operational in the first half of 2026 supporting the supply constraints in Colombia's domestic LPG market. The LPG project will generate between $10 and $15 million in yearly project EBITDA once it reaches its target capacity. The Company continues to pursue strategic investment opportunities to maximize the port's infrastructure and drive long-term value creation.

The Reficar connection's construction was completed, and the Port's efforts have shifted to working together with Ecopetrol to start utilizing the connection establish Puerto Bahia as a strategic partner for the Reficar Refinery.

At the beginning of 2026, Puerto Bahía secured a take-or-pay agreement with Ecopetrol, subject to certain conditions precedent, to develop an LNG regasification project, providing integrated logistics and regasification services to Reficar and the Colombian Natural Gas Transportation System (SNT). The project is expected to benefit from Puerto Bahía's existing and robust port facilities and operating platform, including the repurposing of the Reficar connection, enabling an accelerated development timeline and faster time-to-market. The project contemplates two phases, with an initial regasification capacity of approximately 126 MMcfd anticipated to increase to at least 300 MMcfd by 2029. The services are planned to be available in the fourth quarter of 2026, and the agreement contemplates an up to seven-year service term commencing from the start of operations, with options to extend for an additional five years by mutual agreement.

Water Treatment Facility and Palm Oil Plantation

In 2021, Frontera launched a feasibility analysis of the agricultural water reuse system SAARA, which of a reverse osmosis water treatment facility built in 2016 that the Company began recommissioning in 2023. The plant makes use of the availability of production water from the Quifa and Rubiales blocks. It was designed to remove salts from the treated water to make it suitable for irrigating industrial crops.

Through its wholly-owned subsidiary ProAgrollanos, the Company operates a palm oil business located in the municipality of Puerto Gaitan, in the department of Meta, Colombia. With approximately 2,800 hectares currently planted, its oil palm plantation yielded 28,128 tons of fresh fruit bunches during the year 2025. These crops have an estimated remaining productive lifespan of approximately 20 years.

Most of the water treated by SAARA is reused in agricultural activities carried out by ProAgrollanos with the aim of improving palm crop productivity over the next 24 months. For the year ended December 31, 2025, SAARA processed approximately 49 million barrels of water, that irrigated approximately 800 hectares of palm oil crops in ProAgrollanos.

As part of the Parex Arrangement Agreement, Frontera is selling the SAARA and ProAgrollanos assets, given their close operational linkage to supporting activities in the Quifa block. Following the closing of the Parex Arrangement Agreement, Frontera's Infrastructure Colombia business will no longer include SAARA or ProAgrollanos.

The income statement and key balance sheet information from SAARA and ProAgrollanos, are as follows:

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Revenue	4,310	2,371	14,308	6,380
Fresh fruit bunches for palm oil	1,636	1,253	6,047	4,423
SAARA	2,674	1,118	8,261	1,957
Costs	(4,468)	(3,011)	(17,031)	(9,880)
Fresh fruit bunches for palm oil	(1,086)	(1,352)	(4,542)	(4,216)
SAARA	(3,382)	(1,659)	(12,489)	(5,664)
General and administrative expenses	(231)	(117)	(684)	(476)
Depreciation, amortization and impairment expense	(10,491)	(220)	(12,281)	(772)
SAARA and palm oil plantation operating loss	**(10,880)**	**(977)**	**(15,688)**	**(4,748)**

The following table shows the key performance measures from SAARA and ProAgrollanos:

		Three months ended December 31		Year ended December 31	
($M)		**2025**	**2024**	**2025**	**2024**
Fresh fruit bunches for palm oil (produced - sold)	(Tons)	7,191	6,183	28,128	25,357
Production per hectare per year [(1)]	(Tons/ha/year)	9.73	8.40	9.73	8.40
Palm oil fruit price	($/Ton)	228	203	215	174
Volumes of reverse osmosis water treated	(bwpd)	181,637	78,716	135,158	44,121
Volumes of water irrigated for palm oil cultivation [(2)]	(bwpd)	171,685	80,276	130,863	40,837

(1) Tons per hectare per year for the three months ended December 31, are calculated using the total production for the last 12 months ended December 31.

(2) Differences between the water received and water irrigated are due to the water undergoing treatment or being temporarily stored within the plant's facilities.

For the three months and the year ended December 31, 2025, sales from fresh fruit bunches of oil palm totaled $1.6 million and $6.0 million, respectively, (2024: $1.3 million and $4.4 million, respectively). For the three months and the year ended December 31, 2025, sales from fresh fruit bunches increased by 31% and 37%, respectively, mainly due to higher fresh fruit bunch production and additionally, for the year, due to the increase in market prices. Fluctuations in fruit production volumes are part of normal crop production cycles, as well as the result of other factors, including climate conditions, workforce availability, community blockades near the crop area, and agricultural practices (e.g. fertilization).

During the three months and the year ended December 31, 2025, the volumes of water received and used to irrigate palm oil plantations were higher, compared with the same periods of 2024, mainly due to the temporary suspension of plant operations following the conclusion of the project's pilot program on January 31, 2024. Operations resumed in June 2024 after the signing of an agreement with Ecopetrol to start the first phase of the SAARA project.

For the three months ended December 31, 2025, volumes reached an average of 181,637 bwpd for the quarter, The Company achieved maximum throughput capacity of 230,000 bwpd of water, gaining momentum towards its goal of 250,000 bwpd.

Non-IFRS and Other Financial Measures

This MD&A contains various "**non-IFRS financial measures**" (equivalent to "**non-GAAP financial measures**", as such term is defined in NI 52-112), "**non-IFRS ratios**" (equivalent to "**non-GAAP ratios**", as such term is defined in NI 52-112), "**supplementary financial measures**" (as such term is defined in NI 52-112) and "**capital management measures**" (as such term is defined in NI 52-112), which are described in further detail below. Such measures do not have standardized IFRS definitions. The Company's determination of these non-IFRS financial measures may differ from other reporting issuers and they are therefore unlikely to be comparable to similar measures presented by other companies. Furthermore, these financial measures should not be considered in isolation or as a substitute for measures of performance or cash flows as prepared in accordance with IFRS. These financial measures do not replace or supersede any standardized measure under IFRS. Other companies in the Company's industry may calculate these measures differently than we do, limiting their usefulness as comparative measures.

The Company discloses these financial measures, together with measures prepared in accordance with IFRS, because management believes they provide useful information to investors and shareholders, as management uses them to evaluate the operating performance of the Company. These financial measures highlight trends in the Company's core business that may not otherwise be apparent when relying solely on IFRS financial measures. Further, management also uses non-IFRS measures to exclude the impact of certain expenses and income that management does not believe reflect the Company's underlying operating performance. The Company's management also uses non-IFRS measures in order to facilitate operating performance comparisons from period to period and to prepare annual operating budgets and as a measure of the Company's ability to finance its ongoing operations and obligations.

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

Non-IFRS Financial Measures

*Operating EBITDA from Continuing Operations **

EBITDA is a commonly used non-IFRS financial measure that adjusts net loss as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA from continuing operations is a non-IFRS financial measure that represents the operating results of the Company's primary business, excluding the following items: restructuring, severance and other costs, post-termination obligation, trunkline costs, temporal taxes, payments of minimum work commitments and, certain non-cash items (such as impairments, foreign exchange, unrealized risk management contracts, share-based compensation and debt extinguishment cost) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA from continuing operations, as they are not indicative of the underlying core operating performance of the Company.

The following table provides a reconciliation of net loss to Operating EBITDA from continuing operations:

	Three months ended December 31		Year ended December 31	
($M)	**2025**	**2024**	**2025**	**2024**
Net loss for the period from continuing operations [1]	(663,354)	(20,485)	(1,020,361)	(18,628)
Finance income	(1,392)	(1,851)	(6,677)	(8,363)
Finance expenses	18,888	21,473	71,333	73,252
Income tax expense (recovery)	21,522	35,594	(22,557)	99,324
Depletion, depreciation and amortization	75,115	62,737	275,419	254,791
Colombian temporary taxes [2]	1,983	—	7,233	—
Expense (recovery) of asset retirement obligation	1,691	(2,214)	5,500	2,335
Impairment expense	620,436	18,205	1,063,169	19,985
Trunkline costs	162	1,485	2,162	5,314
Post-termination obligation	740	705	3,339	577
Share-based compensation	1,063	827	2,746	1,685
Restructuring, severance and other costs	2,279	2,096	21,084	5,312
Share of income from associates	(14,107)	(13,200)	(59,197)	(53,912)
Foreign exchange loss	4,357	1,795	2,595	11,041
Other loss (income)	6,359	(6,696)	(7,008)	672
Unrealized (gain) loss on risk management contracts	(2,306)	10,035	(7,518)	13,976
Realized loss (gain) on risk management contract for ODL dividends received	1,076	(921)	2,297	(633)
Non-controlling interests	(4,242)	35	(18,206)	(609)
Gain on repurchase of senior unsecured notes net of consent solicitation	(1,363)	—	(13,288)	(1,001)
Debt extinguishment cost	—	—	5,964	—
Operating EBITDA from continuing operations	**68,907**	**109,620**	**308,029**	**405,118**

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.
[1] Refers to net loss for the period from continuing operations attributable to equity holders of the Company.
[2] These temporary taxes include a 1% contribution on the export of hydrocarbons in Colombia (Catatumbo Tax) resulting from the state of internal commotion declared by the Government of Colombia.

Capital Expenditures

Capital expenditures is a non-IFRS financial measure that reflects the cash and non-cash items used by the Company to invest in capital assets. This financial measure considers oil and gas properties, plant and equipment, infrastructure, exploration and evaluation assets expenditures which are items reconciled to the Company's Statements of Cash Flows for the period.

	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Consolidated Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	54,710	93,074	205,800	311,759
Additions to exploration and evaluation assets	1,567	1,471	5,244	11,749
Total additions in Consolidated Statements of Cash Flows	**56,277**	**94,545**	**211,044**	**323,508**
Non-cash adjustments (1)	(3,030)	(7,520)	(1,808)	(30,343)
Cash adjustments (2)	—	(2,481)	(43)	(2,481)
Total Capital Expenditures from Continuing Operations	**53,247**	**84,544**	**209,193**	**290,684**
Capital Expenditures attributable to Infrastructure Colombia Segment	2,828	25,999	15,706	47,882
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	50,419	58,545	193,487	242,802
Total Capital Expenditure from Continuing Operations	**53,247**	**84,544**	**209,193**	**290,684**

(1) Related to material consumption movements, capitalized non-cash items and other adjustments.

(2) Investments related to the replacement and repairs of the affected assets in the Quifa block due to unexpected failures in a trunkline.

Adjusted Infrastructure Colombia Calculations

Each of Adjusted Infrastructure Revenue, Adjusted Infrastructure Operating Costs and Adjusted Infrastructure General and Administrative, is a non-IFRS financial measure and each is used to evaluate the performance of the Infrastructure Colombia Segment operations. Adjusted Infrastructure Revenue includes revenues of the Infrastructure Colombia Segment including ODL's revenue direct participation interest. Adjusted Infrastructure Operating Costs includes costs of the Infrastructure Colombia Segment including ODL's cost direct participation interest. Adjusted Infrastructure General and Administrative includes general and administrative costs of the Infrastructure Colombia Segment including ODL's general and administrative direct participation interest.

A reconciliation of each of Adjusted Infrastructure Revenue, Adjusted Infrastructure Operating Costs and Adjusted Infrastructure General and Administrative is provided below.

	Three months ended December 31		Year ended December 31	
($M) (1)	**2025**	**2024**	**2025**	**2024**
Revenue Infrastructure Colombia Segment	17,065	13,873	60,055	48,542
Revenue from ODL	99,769	89,728	374,235	351,000
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL (1)	34,919	31,405	130,982	122,850
Adjusted Infrastructure Revenues	**51,984**	**45,278**	**191,037**	**171,392**
Operating cost Infrastructure Colombia Segment	(12,007)	(8,099)	(42,674)	(31,438)
Operating Cost from ODL	(16,753)	(16,270)	(54,684)	(54,020)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL (1)	(5,864)	(5,695)	(19,140)	(18,908)
Adjusted Infrastructure Operating Costs	**(17,871)**	**(13,794)**	**(61,814)**	**(50,346)**
General and administrative Infrastructure Colombia Segment	(1,537)	(1,507)	(5,653)	(5,903)
General and administrative from ODL	(5,814)	(6,985)	(19,788)	(22,628)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL (1)	(2,035)	(2,445)	(6,925)	(7,920)
Adjusted Infrastructure General and Administrative	**(3,572)**	**(3,952)**	**(12,578)**	**(13,823)**

(1) Revenues and expenses related to ODL are accounted for using the equity method, as described in Note 18 of the 2025 Annual Consolidated Financial Statements.

Adjusted Infrastructure Cash and Adjusted Infrastructure Debt is a non-IFRS financial measure or contains a non-IFRS financial measure, and is used to evaluate the performance of the Infrastructure Colombia Segment cash position and monitor the Infrastructure Colombia Segment's debt. Adjusted Infrastructure Cash includes cash of the Infrastructure Colombia Segment including ODL's cash direct participation interest. Adjusted Infrastructure Debt includes debt of the Infrastructure Colombia Segment including ODL's debt direct participation interest.

A reconciliation of each of Adjusted Infrastructure Cash and Adjusted Infrastructure Debt is provided below.

($M) [1]	December 31 2025	December 31 2024
Cash and cash equivalents - unrestricted	230,489	192,577
Cash and cash equivalents of Non-Infrastructure Colombia Segment	(214,406)	(147,097)
Total Cash Infrastructure Colombia Segment	16,083	45,480
Cash and cash equivalent from ODL	53,594	76,979
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	18,758	26,943
Adjusted Infrastructure Cash	**34,841**	**72,423**
Short-Term and Long-Term Debt	474,004	493,764
Debt of Non-Infrastructure Colombia Segment	(306,820)	(389,803)
Total Loans of Infrastructure Colombia Segment	167,184	103,961
Debt from ODL	39,382	36,954
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	13,784	12,934
Adjusted Infrastructure Debt	**180,968**	**116,895**

[1] 35% ODL participation is accounted using the equity method in the 2025 Annual Consolidated Financial Statements, Cash and cash equivalents, and Debt related to the ODL are embedded in the value of the Investment in Associates.

Adjusted Infrastructure EBITDA

The Adjusted Infrastructure EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the Infrastructure Colombia Segment business, including ODL's EBITDA direct participation interest.

	Three months ended December 31		Year ended December 31	
($M)	2025	2024	2025	2024
Adjusted Infrastructure Revenue	51,984	45,278	191,037	171,392
Adjusted Infrastructure Operating Costs	(17,871)	(13,794)	(61,814)	(50,346)
Adjusted Infrastructure General and Administrative	(3,572)	(3,952)	(12,578)	(13,823)
Adjusted Infrastructure EBITDA	**30,541**	**27,532**	**116,645**	**107,223**

Net Sales

Net sales from continuing operations is a non-IFRS financial measure that adjusts revenue to include realized gains and losses from oil risk management contracts while removing the cost of any volumes purchased from third parties. This is a useful indicator for management, as the Company hedges a portion of its oil production using derivative instruments to manage exposure to oil price volatility. This metric allows the Company to report its realized net sales after factoring in these oil risk management activities. The deduction of cost of diluent and oil purchased is helpful to understand the Company's sales from continuing operations performance based on the net realized proceeds from its own production, the cost of which is partially recovered when the blended product is sold. Net sales also exclude sales from port services, as it is not considered part of the oil and gas segment. Refer to the reconciliation in the "Sales" section on page 13.

Operating Netback from Continuing Operations

Operating netback from continuing operations is a non-IFRS financial measure and operating netback from continuing operations per boe is a non-IFRS ratio. Operating netback from continuing operations per boe is used to assess the net margin of the Company's production Colombia after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel and is an indicator of how efficient the Company is at extracting and selling its product. For netback purposes, the Company removes the results of the Infrastructure Colombia Segment from the per barrel metrics and adds the effects attributable to transportation and operating costs of any realized gain or loss on foreign exchange risk management contracts. Refer to the reconciliation in the "Operating Netback from continuing operations" section on page 11.

*Oil and Gas Sales, Net of Purchases, from Continuing Operations **

Oil and gas sales from continuing operations, net of purchases, is a non IFRS financial measure that is calculated using oil and gas sales less the purchased crude net margin. Produced crude oil and gas sales from continuing operations per boe and Oil and gas sales from continuing operations, net of purchases per boe, are a non IFRS ratio that are calculated using Produced crude oil and gas sales per boe, and the oil and gas sales, net of purchases, divided by the total sales volumes, net of purchases.

A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2025	**2024**	**2025**	**2024**
Produced crude oil and products sales ($M) (1)	184,045	219,070	764,855	854,111
Purchased crude net margin ($M) (2)(3)	(7,007)	(11,552)	(37,311)	(38,118)
Oil and gas sales, net of purchases ($M) (2)	**177,038**	**207,518**	**727,544**	**815,993**
Sales volumes, net of purchases - (boe)	3,092,304	3,254,592	11,976,745	11,707,608
Produced crude oil and gas sales ($/boe)	59.52	67.31	63.86	72.95
Oil and gas sales, net of purchases ($/boe) (2)	57.25	63.76	60.74	69.70

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 19 for further details.

(1) Excludes sales from infrastructure services, as they are not part of the oil and gas segment. Refer to the “Infrastructure Colombia” section on page 24 for further details.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Purchased crude net margin is a non-IFRS financial measure calculated using purchased crude oil and product sales, less the cost of those volumes purchased from third parties including transportation and refining costs. Please see the calculation below.

Non-IFRS Ratios

*Realized oil price, net of purchases, and realized gas price per boe **

Realized oil price, net of purchases, and realized gas price per boe are both non-IFRS ratios. Realized oil price, net of purchases, per boe is calculated using oil sales net of purchases, divided by total sales volumes, net of purchases. Realized gas price is calculated using sales from gas production divided by the conventional natural gas sales volumes.

	Three months ended December 31		Year ended December 31	
	2025	**2024**	**2025**	**2024**
Oil and gas sales, net of purchases ($M) (1)(2)	177,038	207,518	727,544	815,993
Crude oil sales volumes, net of purchases - (bbl)	3,008,810	3,213,578	11,742,389	11,500,286
Conventional natural gas sales volumes - (mcf)	475,857	234,321	1,335,483	1,183,171
Realized oil price, net of purchases ($/bbl) (2)	57.19	64.08	61.00	70.30
Realized conventional natural gas price ($/mcf)	10.42	6.78	8.45	6.37

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 19 for further details.

(1) Non-IFRS financial measure.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

Net sales realized price *

Net sales realized price is a non-IFRS ratio that is calculated using net sales (including oil and gas sales net of purchases, realized gains and losses from oil risk management contracts and less royalties). Net sales realized price per boe is a non-IFRS ratio which is calculated dividing each component by total sales volumes, net of purchases.

A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2025	**2024**	**2025**	**2024**
Oil and gas sales, net of purchases ($M) [(1)(2)]	177,038	207,518	727,544	815,993
(Loss) gain on oil price risk management contracts, net ($M) [(3)]	(1,186)	253	(8,680)	(8,457)
(-) Royalties ($M)	(2,241)	(2,599)	(9,448)	(14,704)
Net sales ($M)	173,611	205,172	709,416	792,832
Sales volumes, net of purchases - (boe)	3,092,304	3,254,592	11,976,745	11,707,608
Oil and gas sales, net of purchases ($/boe) [(2)]	57.25	63.76	60.74	69.70
Premiums received (paid) on oil price risk management contracts [(3)(4)]	(0.38)	0.08	(0.72)	(0.72)
Royalties ($/boe) [(4)]	(0.73)	(0.80)	(0.79)	(1.26)
Net sales realized price ($/boe) [(2)]	56.14	63.04	59.23	67.72

* Figures from 2014 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page19 for further details.

(1) Non-IFRS financial measure.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

(3) Includes the net amount of put premiums paid for expired positions and the positive cash settlement received from oil price contracts during the period. Refer to the “Gain (Loss) on Risk Management Contracts” section on page 18 for further details.

(4) Supplementary financial measure.

Purchased crude net margin *

Purchased crude net margin is a non-IFRS financial measure that is calculated using the purchased crude oil and products sales, less the cost of those volumes purchased from third parties including its transportation and refining costs. Purchased crude net margin per boe is a non-IFRS ratio that is calculated using the purchased crude net margin, divided by the total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2025	**2024**	**2025**	**2024**
Purchased crude oil and products sales ($M)	43,141	54,469	194,015	202,752
(-) Cost of diluent and oil purchased ($M) [(1)]	(49,375)	(65,375)	(229,094)	(235,944)
Puerto Bahía inter-segment costs [(2)]	(773)	(646)	(2,232)	(4,926)
Purchased crude net margin ($M) [(2)]	**(7,007)**	**(11,552)**	**(37,311)**	**(38,118)**
Sales volumes, net of purchases - (boe)	3,092,304	3,254,592	11,976,745	11,707,608
Purchased crude net margin ($/boe) [(2)]	**(2.27)**	**(3.55)**	**(3.12)**	**(3.25)**

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the “Discontinued Operations” section on page 19 for further details.

(1) Cost of third-party volumes purchased for use and resale in the Company's oil operations, including associated transportation and refining costs.

(2) 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to diluent and oil purchases as well as transportation costs.

Production costs (excluding energy costs), net of realized FX hedge impact, and production cost (excluding energy costs), net of realized FX hedge impact per boe *

Production costs (excluding energy costs), net of realized FX hedge impact is a non-IFRS financial measure that mainly includes lifting costs, activities developed in the blocks, processes to put the crude oil and gas in sales condition and the realized gain or loss on foreign exchange risk management contracts attributable to production costs. Production cost, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using production cost (excluding energy costs), net of realized FX hedge impact divided by production (before royalties).

A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Production costs (excluding energy costs) ($M)	33,493	27,628	128,296	134,694
(-) Realized gain on FX hedge attributable to production costs (excluding energy costs) ($M) [1]	(1,367)	—	(2,615)	(3,358)
SAARA inter-segment costs	1,872	783	5,783	1,370
Production costs (excluding energy costs), net of realized FX hedge impact ($M) [2]	33,998	28,411	131,464	132,706
Production Colombia (boe)	3,526,544	3,740,352	14,239,015	14,136,018
Production costs (excluding energy costs), net of realized FX hedge impact ($/boe)	9.64	7.60	9.23	9.39

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

[1] See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

[2] Non-IFRS financial measure.

*Energy costs, net of realized FX hedge impact, and production cost, net of realized FX hedge impact per boe **

Energy costs, net of realized FX hedge impact is a non-IFRS financial measure that describes the electricity consumption and the costs of localized energy generation and the realized gain or loss on foreign exchange risk management contracts attributable to energy costs. Energy costs, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using energy costs, net of realized FX hedge impact divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Energy costs ($M)	22,595	20,439	79,546	75,622
(-) Realized gain on FX hedge attributable to energy costs ($M) [1]	(677)	—	(1,366)	(1,267)
Energy costs, net of realized FX hedge impact ($M) [2]	21,918	20,439	78,180	74,355
Production Colombia (boe)	3,526,544	3,740,352	14,239,015	14,136,018
Energy costs, net of realized FX hedge impact ($/boe)	6.22	5.46	5.49	5.26

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador.

[1] See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

[2] Non-IFRS financial measure.

*Transportation costs, net of realized FX hedge impact, and transportation costs, net of realized FX hedge impact per boe **

Transportation costs, net of realized FX hedge impact is a non-IFRS financial measure, that includes all commercial and logistics costs associated with the sale of produced crude oil and gas such as trucking and pipeline, and the realized gain or loss on foreign exchange risk management contracts attributable to transportation costs. Transportation cost, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using transportation cost, net of realized FX hedge impact divided by net production after royalties. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Transportation costs ($M)	38,544	38,645	154,426	146,741
(-) Realized gain on FX hedge attributable to transportation costs ($M) [1]	(761)	—	(1,628)	(982)
Puerto Bahía inter-segment costs [2]	887	507	2,991	2,021
Transportation costs, net of realized FX hedge impact ($M) [2][3]	38,670	39,152	155,789	147,780
Net production Colombia (boe)	3,245,024	3,377,136	12,984,510	12,524,154
Transportation costs, net of realized FX hedge impact ($/boe) [2]	11.92	11.59	12.00	11.80

* Figures from 2024 reporting periods were changed due to the re-presentation of continuing operations following the divestment of non-core assets in Ecuador. Refer to the "Discontinued Operations" section on page 19 for further details.

[1] See "Gain (Loss) on Risk Management Contracts" on page 18 for further details.

[2] 2024 comparative figures differ from those previously reported due to the inclusion of Puerto Bahia inter-segment costs related to transportation costs.

[3] Non-IFRS financial measure.

Supplementary Financial Measures

Realized gain (loss) on oil risk management contracts per boe

Realized gain (loss) on oil risk management contracts includes the gain or loss during the period, as a result of the Company's exposure in derivative contracts of crude oil. Realized gain (loss) on oil risk management contracts per boe is a supplementary financial measure that is calculated using Realized gain (loss) on risk management contracts divided by total sales volumes, net of purchases.

Royalties per boe

Royalties includes royalties and amounts paid to previous owners of certain blocks in Colombia and cash payments for PAP. Royalties per boe is a supplementary financial measure that is calculated using the royalties divided by total sales volumes, net of purchases.

NCIB (as defined below) weighted-average price per share

Weighted-average price per share under the 2023 NCIB (as defined below) and 2025 NCIB (as defined below) is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under such normal course issuer bids during the periods. It is calculated using the total amount of common shares repurchased in U.S. dollars divided by the number of Common Shares repurchased.

Capital Management Measures

Net working capital

Net working capital is a capital management measure to describe the liquidity position and ability to meet its short-term liabilities. Net working capital is defined as current assets less current liabilities.

Restricted cash short- and long-term

Restricted cash (short- and long-term) is a capital management measure, that sums the short-term portion and long-term portion of the cash that the Company has in term deposits that have been escrowed to cover future commitments and future abandonment obligations, or insurance collateral for certain contingencies and other matters that are not available for immediate disbursement.

Total cash

Total cash is a capital management measure to describe the total cash and cash equivalents restricted and unrestricted available, comprised of cash and cash equivalents and restricted cash short and long-term.

Total debt and lease liabilities

Total debt and lease liabilities are capital management measures to describe the total financial liabilities of the Company, and is comprised of the 2028 Unsecured Notes (as defined below), loans and liabilities from leases of various properties, power generation supply, vehicles and other assets.

6. LIQUIDITY AND CAPITAL RESOURCES

The Company's principal liquidity and capital resource requirements include:

- capital expenditures for exploration, production, development and infrastructure, including growth plans;
- costs and expenses related to operations, commitments, and existing contingencies;
- debt service requirements related to existing and future debt; and
- shareholder returns through share repurchases and/or dividends payments.

The Company funds its anticipated cash requirements and strategic objectives through current cash and working capital balances, cash flows from operations, and available debt and credit facilities. In accordance with the Company's investment policy, available cash balances are held in interest-bearing savings accounts, term deposits and Colombian mutual funds with high credit ratings and liquidity. The Company regularly reviews its capital structure and liquidity sources, with a focus on ensuring that capital resources are sufficient to meet operational needs and other obligations.

As at December 31, 2025, the Company had a total cash balance of $241.8 million (including $11.3 million in restricted cash), which was $19.0 million higher than cash balances as of December 31, 2024.

For the year ended December 31, 2025, the Company generated $422.4 million, of cash from operations (including cash of $79.0 million from Chevron prepayment (as defined below)), which was used to fund cash outflows of $230.6 million for capital expenditures and other investing activities. During the same period, financing activities generated net outflows of $169.7 million.

These included $105.2 million in the full repayment of the PIL Loan Facility, $69.2 million in repurchases of the 2028 Unsecured Notes (as defined below), $99.5 million used to repurchase Common Shares under the January 2025 SIB and July 2025 SIB (as defined below), $42.9 million in interest paid and other financing charges, $46.8 million toward principal payments on the FPI Recapitalization Loan, $10.7 million toward principal payments on the Agro Cascada Working Capital Loan, $0.2 million in transaction costs of FPI Recapitalization Loan, $2.6 million used to repurchase Common Shares under the 2025 NCIB, $13.5 million in dividends paid to equity holders and $7.4 million in lease payments, partially offset by $212.4 million in net proceeds from the disbursement of the FPI Recapitalization Loan and $16.1 million in the release of the reserve account of the PIL Loan Facility. The Company's net working capital[(1)] was a deficit of $131.3 million as at December 31, 2025, compared to a deficit of $100.6 million as at December 31, 2024.

The Company believes that its net working capital balances, together with future cash flows from operations and available credit facilities, are sufficient to support the Company's normal operating requirements, capital expenditures, and financial commitments on an ongoing basis.

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As at December 31, 2025, the main components of restricted cash were long-term abandonment funds, as required by the ANH. Abandonment funds are intended to satisfy abandonment obligations and expected to be released over the long-term as assets are abandoned. Abandonment funding requirements are updated annually. As at December 31, 2025, the Company's restricted cash position was $11.3 million, representing a decrease of $18.9 million from December 31, 2024, primarily due to the cancellation of the reserve account of the PIL Loan Facility.

The measures taken by the Company to manage its liquidity and capital resources are ongoing, and the Company continues to pursue additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of these measures, the Company expects that unrestricted cash balances together with future cash flows from operations, available credit facilities, and alternative financing arrangements will be sufficient to support its operational and capital requirements and other financial commitments. The Company intends to remain flexible and disciplined with respect to capital allocation decisions as the current commodity price environment evolves, and may make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 44.

(1) Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'' section on page 29 for further details.

2028 Unsecured Notes

On June 21, 2021, the Company completed the offering of $400.0 million senior unsecured notes due 2028 ("**2028 Unsecured Notes**"). The 2028 Unsecured Notes bear interest at a rate of 7.875% per year, 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 in June 2028, unless earlier redeemed or repurchased.

On May 9, 2025, the Company announced that it had commenced a cash tender offer (the "**Offer**") for up to $65.0 million in aggregate principal amount of its outstanding 2028 Unsecured Notes and a concurrent consent solicitation (the "**Solicitation**") with respect to certain proposed amendments (the "**Proposed Amendments**") to the indenture governing the 2028 Unsecured Notes (the "**Indenture**"). The Offer and Solicitation were amended on May 26, 2025 to extend the Early Tender Date and Consent Deadline (as defined in the Offer to Purchase and Consent Solicitation Statement dated as of May 9, 2025) to 5:00 p.m., New York City time, on June 9, 2025 (the "**Extended Early Tender Date and Consent Deadline**"). The Offer and Solicitation were further amended on June 2, 2025 to, among other things: (i) increase the maximum tender amount from $65.0 million to $80.0 million; (ii) increase the payment for those consents validly delivered at or prior to the Extended Early Tender Date and Consent Deadline from $15.00 for each $1,000 principal amount of 2028 Unsecured Notes to an aggregate amount of $8 million, to be divided pro rata among all tendering and consenting holders of 2028 Unsecured Notes ("**Holders**") in the Offer and Solicitation in aggregate (the "**Amended Consent Payment**"); and (iii) increase the consideration payment for each $1,000 principal amount of 2028 Unsecured Notes validly tendered at or prior to the Extended Early Tender Date and Consent Deadline, and accepted for purchase pursuant to the Offer, from $700.00 to $720.00. As of the Extended Early Tender Date and Consent Deadline, which was also the expiry time of the Offer, the Company received without duplication: (i) validly delivered tenders from Holders representing $134,169,000 in aggregate principal amount 2028 Unsecured Notes and (ii) validly delivered consents from Holders (including consents delivered without tenders) representing $194,448,000 (i.e., 50.38%) in aggregate principal amount of 2028 Unsecured Notes outstanding. Therefore, the Company obtained the requisite consents to the Proposed Amendments under the Indenture and proceeded to execute a supplemental indenture incorporating the Proposed Amendments, paid to consenting Holders the Amended Consent Payment, and repurchased and proceeded to cancel $80.0 million in face value of its 2028 Unsecured Notes. As of the completion of the Offer and Solicitation, the Company has $320.0 million in principal amount of 2028 Unsecured Notes outstanding, including $10.0 million held by the Company.

During the three months and the year ended December 31, 2025, the Company repurchased $4.0 million and $85.0 million, respectively, of its 2028 Unsecured Notes pursuant to the Offer and Solicitation and in the open market for a cash consideration of $2.8 million and $61.2 million, respectively. As a result, during the three months and the year ended December 31, 2025, the Company recognized a gain of $1.4 million and $13.3 million, respectively. These gains are after deducting the Amended

Consent Payment of $8.0 million, the proportional deferred financing fees write-offs of $1.0 million, and legal and advisory fees totaling $1.6 million.

The carrying value for the 2028 Unsecured Notes as at December 31, 2025, was $306.8 million (December 31, 2024: $389.8 million).

The purpose of the Offer and the Solicitation was to gain greater financial and operational flexibility while simultaneously reducing the Company's overall debt. Additionally, the Proposed Amendments permitted the Company to take certain actions that were previously restricted under the Indenture. These include, but were not limited to: allowing additional restricted payments (particularly from proceeds of unrestricted subsidiaries); providing greater flexibility in managing working capital to support operational efficiency and financial resilience; increasing the amount of permitted indebtedness and liens; and reducing conditions and requirements that previously limited the Company's ability to pursue strategic transactions aimed at enhancing growth and value.

2028 Unsecured Notes Covenants

The 2028 Unsecured Notes are senior, unsecured notes and rank equally in right of payment with all existing and future senior unsecured debt. As at December 31, 2025, the 2028 Unsecured Notes were guaranteed by the Company's subsidiary, Frontera Energy Colombia Corp. On April 11, 2023, the Company designated Frontera Energy Guyana Holding Ltd. and Frontera Guyana as Unrestricted Subsidiaries and released Frontera Guyana as a note guarantor under the Indenture.

Under the terms of the 2028 Unsecured Notes, the Company (excluding the Unrestricted Subsidiaries) may, among other things, incur indebtedness, provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.25:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.25:1.0. If these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $175.0 million or 15% of consolidated net tangible assets(3). The 2028 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at December 31, 2025, the Company was in compliance with all such covenants.

Pursuant to the requirements under the Indenture, the Company reported consolidated total indebtedness of $429,256,000 as at December 31, 2025, and, for the twelve months ended as of December 31, 2025, a consolidated adjusted EBITDA of $305,811,000 and a consolidated interest expense of $56,934,000.

(1) Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the Indenture as consolidated total indebtedness as at such date divided by consolidated adjusted EBITDA for the most recently ended period of four consecutive fiscal quarters.

a. Consolidated total indebtedness is defined below.
b. Consolidated adjusted EBITDA is defined as the consolidated net (loss) income, as defined in the Indenture, plus: (i) consolidated interest expense; (ii) consolidated income tax and equity tax; (iii) consolidated depletion and depreciation expense; (iv) consolidated amortization expense; and (v) consolidated impairment charge, exploration expense, and abandonment costs, after excluding the impact of the Unrestricted Subsidiaries.

(2) Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most recently ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period, as defined in the Indenture.

(3) Consolidated net tangible assets is defined in the Indenture as the net amount of the Company's total assets, less intangible assets and current liabilities, after excluding the impact of the Unrestricted Subsidiaries.

Consolidated Total Indebtedness and Net Debt

Consolidated total indebtedness and net debt are used by the Company to monitor its capital structure financial leverage, and as measures of overall financial strength. Consolidated total indebtedness is defined as long-term debt, plus lease liabilities and the net position of risk management contracts, excluding the Unrestricted Subsidiaries. This metric is consistent with the definition under the Indenture for the calculation of certain conditions and covenants. Net debt is defined as consolidated total indebtedness less unrestricted cash and cash equivalents. Both measures exclude non-recourse subsidiary debt and certain amounts attributable to the Unrestricted Subsidiaries.

The following table reconciles both measures to amounts reported under IFRS:

($M)		As at December 31 2025
Short-term and Long-term debt [(1)]	$	306,821
Total lease liabilities [(2)]		18,529
Customers prepayment [(3)]		106,621
Risk management liability net		(2,715)
Consolidated Total Indebtedness		**429,256**
(-) Cash and Cash Equivalents [(4)]		(209,725)
(=) Net Debt	**$**	**219,531**

(1) Excludes $167.2 million of long-term debt attributable to the Unrestricted Subsidiaries.

(2) Excludes $1.4 million of lease liabilities attributable to the Unrestricted Subsidiaries.

(3) This line includes the customer prepayment relates to one cargo of crude oil to be delivered in the first quarter of 2026, and the Chevron prepayment (as defined below).

(4) Includes unrestricted cash and cash equivalents attributable to the guarantors as at December 31, 2025, Frontera Energy Colombia AG and the issuer (i.e., the Company), as defined in the Indenture.

Frontera Pipeline Investment Loan Facility ("FPI Loan Facility", formerly named PIL Loan Facility) and Frontera Pipeline Investment Recapitalization Loan Facility ("FPI Recapitalization Loan")

On March 27, 2023, FPI entered into a new credit agreement through which lenders provided a $120.0 million loan facility to FPI, secured by substantially all the assets and shares of FPI, Puerto Bahia held by the Company and assets related to Puerto Bahia's liquids terminal. It is guaranteed by Frontera Bahia Holding Ltd. and FEC ODL Holdings Corp. (formerly named Frontera ODL Holding Corp.), the parent company of FPI. The FPI Loan Facility is a five-year credit facility maturing in December 2027, with principal payments made semi-annually. The FPI Loan Facility has two tranches: a $100.0 million amortizing tranche that pays SOFR six-month term plus a margin of 7.25% per annum (with a step down to 6.25% if certain conditions are met) and a $20.0 million bullet maturity tranche that pays a fixed rate of 11.0% per annum. The conditions precedent to the FPI Loan Facility were fully satisfied, and both tranches of the facility were funded on March 31, 2023.

On February 16, 2024, as part of the FPI Loan Facility (Tranche A-2), the Company amended the facility to disburse an accordion tranche of $30.0 million. This tranche secures funding for the connection project between Puerto Bahia's port facility and the Cartagena refinery operated by Refineria de Cartagena S.A.S. On February 23, 2024, August 7, 2024 and December 16, 2024, the lenders disbursed $8.8 million, $10.0 million and $10.0 million, respectively. The accordion tranche was recognized, net of an original issue discount of $1.2 million, primarily related to lender and legal fees, which were discounted at the time of disbursement.

On May 14, 2025, FPI amended and restated its credit agreement through which lenders increased their commitments to $220.0 million. The FPI Recapitalization Loan is comprised of various tranches, the last of which matures in December 2031, with principal payments made semi-annually. The FPI Recapitalization Loan is comprised of: a $140.0 million tranche (FPI Recapitalization Loan First Lien - Floating Rate) that pays SOFR six-month term plus a margin of 6% per annum, a $20.0 million tranche (FPI Recapitalization Loan First Lien - Tranche B) that pays a fixed rate of 11% per annum, a $20.0 million tranche (FPI Recapitalization Loan First Lien - Tranche A) that pays a fixed rate of 9.75% per annum and a $40.0 million tranche (FPI Recapitalization Loan Second Lien - Fixed Rate) that pays a fixed rate of 15% per annum.

Apart from extending the term of the $100.8 outstanding amount (for further information, refer to Note 13 of the Interim Condensed Consolidated Financial Statements for the three months ended March 31, 2025), the proceeds of the FPI Recapitalization Loan were used to pay fees and accrued interest. The FPI Recapitalization Loan is guaranteed by FEC ODL Holdings Corp. and is secured exclusively by the cash flows generated from Frontera's interest in ODL, with Puerto Bahia removed from the security package.

As at December 31, 2025, the carrying value of the FPI Loan Facility is $Nil (December 31, 2024: $94.5 million). As at December 31, 2025, the FPI Loan Facility debt service reserve account has a balance of $Nil. (December 31, 2024: $15.9 million). As at December 31, 2025, the carrying value of the FPI Recapitalization Loan is $167.2 million, which includes short-term debt of $42.0 million.

Customer Prepayments

In December 2025, the Company entered into a 24-month agreement to supply 500,000 barrels of crude oil per month with Chevron Products Company ("**Chevron**"). An advance payment of $80 million was received and recorded as a customer prepayment, to be recognized as revenue upon monthly deliveries ("**Chevron Prepayment**"). The sales price will be based on the Brent reference price, adjusted for applicable differentials and discounts, and repayment of the prepayment will begin after a six-month grace period. The Company may request an additional $40 million advance for up to six months on a fully committed basis. Under the agreement, the prepayment amounts will be subject to a financial discount calculated at SOFR plus 4.25% per annum. The cash consideration related to the advance amounted to $79.0 million; the remaining balance corresponds to contract-obtaining costs discounted upfront.

As at December 31, 2025, customer prepayments are principally attributable to the advance payment received under the crude oil supply agreement described above. As at December 31, 2025, the carrying value for customer prepayments was $106.6 million (2024: $30.3 million), which includes short-term prepayments of $48.8 million. The short-term carrying amount includes an existing Chevron prepayment agreement, which expired at the end of January 2026 of $26.6 million.

Agro Cascada Working Capital Loan

On October 10, 2024, the Company entered into a one-year working capital loan agreement with Citibank Colombia S.A., denominated in COP, with a principal amount of COP $41,927 million (equivalent to $9.5 million), maturing on October 10, 2025, with an interest rate of IBR(1) plus 2.5%, payable monthly (the "**Agro Cascada Working Capital Loan**"). On October 10, 2024 and November 21, 2024, the lender disbursed COP $29,337 million and COP $12,590 million, respectively. The proceeds of the Agro Cascada Working Capital Loan were intended to support the development of the Company's water treatment facilities, and it is guaranteed by Frontera Energy Colombia Corp., Sucursal Colombia.

The Company fully repaid the loan on October 10, 2025. As at December 31, 2025, the carrying value of the Agro Cascada Working Capital Loan was $Nil (2024: $9.5 million).

(1) Reference Banking Indicator from the central bank of Colombia ("IBR" for its acronym in Spanish).

Letters of Credit

The Company has various uncommitted bilateral letters of credit. As at December 31, 2025, the Company had issued letters of credit and guarantees for exploration and abandonment funds totaling $119.5 million (against total credit lines of $172.5 million), without cash collateral.

CPE-6 Solar Plant Project Leasing Agreement

During the fourth quarter of 2022, the Company executed a leasing agreement with Bancolombia to finance the construction and commissioning of a solar power plant project in the CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, with an equivalent value of approximately to $6.8 million as at December 31, 2025, expiring on July 20, 2030 from April 3, 2024 (the maturity was extended during 2025; initially, it was 72 months). The Solar Plant Debt bears interest equivalent to IBR + 3.00% (the rate was modified during 2025; initially it was IBR + 5.75%), payable monthly on the outstanding amount. As at December 31, 2025, the outstanding balance was $5.6 million. The Company recognized this obligation as a lease liability.

CPE-6 Battery Energy Storage System Leasing Agreement

During the fourth quarter of 2023, the Company executed a leasing agreement with Bancolombia to finance the Battery Energy Storage System at the CPE-6 block (the "**BESS Project**"). The financing is denominated in COP, with an equivalent value of approximately $1.0 million as at December 31, 2025, and has a maturity date of April 9, 2029. The BESS Project leasing bears interest equivalent to IBR plus 5.10%, payable monthly. As at December 31, 2025, the outstanding balance was $0.6 million. The Company recognized this obligation as a lease liability.

Commitments and Contractual Obligations

The Company's commitments as at December 31, 2025, undiscounted by calendar year, are presented below:

As at December 31, 2025 ($M)	2026	2027	2028	2029	2030	Subsequent to 2031	Total
Short-term and long-term debt principal and interest	86,279	82,816	369,136	28,465	28,441	—	595,137
Lease liabilities	8,498	4,153	4,025	3,343	2,107	6,447	28,573
Total financial obligations	**94,777**	**86,969**	**373,161**	**31,808**	**30,548**	**6,447**	**623,710**
Transportation							
Ocensa P-135 ship-or-pay agreement	12,690	—	—	—	—	—	12,690
ODL agreements	925	—	—	—	—	—	925
Other transportation and processing commitments	13,985	1,420	—	—	—	—	15,405
Exploration and evaluation							
Minimum work commitments (1)	—	15,687	6,880	5,066	—	—	27,633
Other commitments							
Operating purchases, community obligations and others (2)	119,432	258	259	264	270	2,407	122,890
Energy supply commitments (3)	23,622	11,478	11,908	8,249	8,496	8,741	72,494
Total Commitments	**170,654**	**28,843**	**19,047**	**13,579**	**8,766**	**11,148**	**252,037**

(1) On August 28, 2025, the Company received a communication from ANH confirming the acceptance of the transfer of the investment commitment from Llanos 119 to Vim-46, amounting to $6.8 million. This does not imply any decrease or increase in the minimum exploration commitments.

(2) It does not include the commitments associated with the LPG project in Puerto Bahia, which are fully assumed by the partner according to the JOA agreement.

(3) 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.

Oleoducto Central S.A. ("Ocensa") and Cenit Pledge

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit became effective, as a result, the pledged inventory crude oil is stored in Cenit's terminal of Coveñas (TLU-3) instead of Ocensa's terminal. On March 31, 2022, the Company signed a new pledge agreement with Ocensa and Cenit, which guarantees the payment obligations of both contracts, up to $30.0 million and $6.0 million, respectively. On July 16, 2025, the overall guaranteed amount was reduced to $21.0 million (up to $15.0 million with Ocensa and $6.0 million with Cenit) and the term of the pledge agreement was extended to December 31, 2026, with Ocensa and to January 31, 2027, with Cenit.

Overriding Royalty Interest CPE-6

As part of the Company's acquisition of Repsol Colombia Oil & Gas Ltd.'s ("RCOG") 50% working interest in the CPE-6 block, the Company granted a pledge to RCOG over the production from the CPE-6 block to guarantee the payments, of up to a maximum of $48.0 million. Under the farm-out agreement, two kinds of payments are set, each contingent on production from this block and each applicable until the maximum payment of $48.0 million is paid: (i) a variable monthly payment, and (ii) three potential production milestone payments of $5.0 million each when 5 million, 10 million and 20 million total barrels production, respectively, are achieved. As at December 31, 2025, the Company has an outstanding payment of $14.4 million.

Contingencies

The Company is involved in various claims and litigation arising from the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company's financial position, results of operations or cash flows.

Corentyne License

The Joint Venture jointly holds 100% working interest in the Corentyne block, located offshore Guyana. Frontera Guyana and CGX Resources have agreed that their respective participating interests are 72.52% and 27.48%, which includes a 4.52% interest which CGX Resources agreed to assign to Frontera Guyana in 2023. This assignment remains subject to the approval of the Government of Guyana ("**GoG**") but is enforceable between Frontera Guyana and CGX Resources.

On June 26, 2024, the Company and CGX Energy Inc. announced that the Joint Venture submitted a notice of potential commercial interest for the Wei-1 discovery to the GoG, which preserves their interests in the Petroleum Prospecting License ("**PPL**") and the Petroleum Agreement ("**PA**") for the Corentyne block. On December 12, 2024, the Company and CGX Energy

Inc. announced that the Joint Venture had sent the GoG a letter activating a 60-day period for the parties to the PA to make all reasonable efforts to amicably resolve all disputes via negotiation. On February 11, 2025, the Company and CGX Energy Inc. announced that the Joint Venture received a communication from the GoG in which the Government has taken the position that the PPL has terminated or, alternatively, that the communication served as a 30-day notice of the Government's intention to cancel the PPL, but that the Government invites the Joint Venture to submit representations for the Government to consider in making its final decision as to whether or not to cancel the PPL. On February 24, 2025, CGX Energy Inc. announced that the Joint Venture had provided a response advising the GoG that notwithstanding the Government's contradictory positions, both the PPL and the PA remain valid and in force. On March 13, 2025, the Company and CGX Energy Inc. announced that the Joint Venture received a communication from the GoG indicating that, on the one hand, the Government was of the view that the PPL and PA are at an end but, on the other hand, that the Government was terminating the PA and cancelling the PPL. On March 26, 2025, the Company and its subsidiaries, Frontera Petroleum International Holding B.V. and Frontera Energy Guyana Holding Ltd. (the "**Investors**") delivered a notice of intent to the GoG. In this Notice, the Investors alleged breaches of the United Kingdom–Guyana Bilateral Investment Treaty and the Guyana Investment Act by the GoG. This communication triggered a 90-day consultation and negotiation period intended to resolve the dispute amicably ("**Notice of Intent**"). The parties have been unable to reach a mutual resolution to date.

On July 23, 2025, the GoG, through its legal counsel, responded to the Notice of Intent, rejecting the claims regarding the Corentyne block license, and reaffirmed its view that the Joint Venture's interest expired on June 28, 2024. The Joint Venture has continued to exchange without prejudice communications with the GoG, and remains open to engaging in good faith discussions with the Government.

The Joint Venture continues to firmly maintain that its interests in, and the license for, the Corentyne block remain valid and in good standing and that the PA for such block has not been terminated. While the GoG has publicly stated its position that the Joint Venture's interest expired on June 28, 2024, the Joint Venture strongly disagrees and remains committed to asserting its legal rights under applicable treaties and agreements.

The Company evaluated the Corentyne E&E asset's recoverability given the GoG's conduct and communications, and its unwillingness to recognize the joint venture's rights during the consultation periods, which have since expired. Although all contractual requirements of the Company have been met and an external legal assessment determined that the Company's interests in the licenses and agreements for the Corentyne block remain valid, the GoG's positions mentioned above have restricted the Company's ability to develop activities under those licenses and agreements. This situation has led to uncertainty regarding the asset's future development and constituted an impairment indicator under IFRS 6 and IAS 36. Consequently, the Company recognized an impairment of $432.2 million in its income statement during the second quarter of 2025. The Corentyne E&E asset's carrying value as of December 31, 2025 is $Nil (2024: $431.9 million).

High-Price Clause

The Company has certain exploration and production contracts acquired through business combinations where outstanding disagreements with the ANH existed relating to the interpretation of PAP clauses. These contracts require high-price participation payments to be made to the ANH for each designated exploitation area within a block under contract, which has cumulatively produced five million or more barrels of oil. The disagreement involves whether the cumulative production amounts in an exploitation area should be calculated individually (as each exploitation area represents independent reservoirs) or combined with other exploration areas within the same block for the purpose of determining the five million barrel threshold. The ANH has interpreted that PAP should be calculated on a combined basis as opposed to the Company's interpretation that the calculation should be provided on an individual basis. Upon acquisition of these contracts and in accordance with IFRS 3, *Business Combinations*, provisions for contingent liabilities were recognized regarding these disagreements with the ANH.

On March 13, 2025, the Company obtained a favorable arbitral award in the Cubiro E&P Contract litigation, confirming its contractual rights under the Cubiro E&P Contract. The Tribunal ruled in the Company's favor, rejecting ANH's actions and recognizing the independence of the Copa and Petirrojo exploitation areas. While the award was favorable to the Company, the arbitral tribunal refrained from ruling on the legality of the administrative acts issued by the ANH. Consequently, both parties have filed annulment appeals against the award, which remain pending adjudication.

Puerto Bahía – Arbitration *against* the CITT Consortium relating to the EPC Contract

Puerto Bahia entered into an Engineering, Procurement and Construction ("**EPC**") agreement with the consortium composed of Isolux Ingeniería S.A., Tradeco Industrial S.A. de C.V., and Tradeco Infraestructura S.A. de C.V. (the "**CITT Consortium**") for the construction of the port's hydrocarbons terminal. During the execution of the project, the CITT Consortium incurred material contractual breaches, primarily significant delays and other technical deficiencies. As a result, Puerto Bahía terminated the EPC Contract for cause attributable to the contractor and enforced the performance guarantee (letter of credit) in the amount of USD 17.0 million. The CITT Consortium initiated an international arbitration administered by the International Chamber of Commerce ("**ICC**"), challenging the termination and asserting monetary claims against Puerto Bahía.

On March 1, 2023, the ICC Arbitral Tribunal issued a final award largely in favor of Puerto Bahía. The award confirmed the validity of the termination of the EPC Contract and the legality of the enforcement of the letter of credit, rejected the CITT

Consortium's principal claims, and granted contractual penalties in favor of Puerto Bahía in the approximate amount of USD 24.7 million. The Tribunal also awarded certain specific amounts to the CITT Consortium and, following the offsetting of reciprocal awards, the net result of the award reflected an approximate balance of USD 2.0 million in favor of Puerto Bahía, with an overall favorable economic effect for the Company.

In 2023, the CITT Consortium filed a constitutional action (acción de tutela) against the arbitral award, which was denied by the Supreme Court of Justice and subsequently confirmed on appeal. Thereafter, on April 16, 2024, the CITT Consortium filed an annulment action against the award and its clarifying addendum before the Supreme Court of Justice. Puerto Bahía timely submitted its opposition and, by order dated August 22, 2025, the Court recognized the authority of Puerto Bahía's legal representatives, confirmed the timely filing of the opposition, and referred the case for a decision on the merits. As of the date hereof, the annulment action remains pending.

Based on the analysis conducted by external counsel specialized in international arbitration, the likelihood of annulment of the award is remote. Accordingly, Management considers that a reversal of the favorable outcome is not probable and that no additional provision is required, and the matter continues to be classified as a remote contingency.

Ecopetrol - Rubiales Field Disagreement

Since 2018, Frontera and Ecopetrol have initiated claims against each other before local courts due to disagreements related to the expiration of the Rubiales and Piriri exploration and production contracts.

To settle certain differences under dispute, on December 13, 2023, Frontera and Ecopetrol entered into an agreement which closed 21 (out of 57) disagreements between the parties. As a result, the Company recorded a reversal of a liability provision of $5.9 million recognized during 2016, 2017, 2020, 2021, 2022, and 2023, a reversal of net liabilities with Ecopetrol of $0.5 million and paid to Ecopetrol $4.2 million pursuant to the settlement agreement. Also, as a result of the settlement, Ecopetrol amended the amount of its first lawsuit from $45.0 million to $32.0 million and Frontera withdrew one of the lawsuits filed against Ecopetrol and amended the amount of another one from $9.0 million to $2.6 million.

In addition, Ecopetrol has filed a new lawsuit claiming approximately $4.3 million against Frontera for post-termination activities in Rubiales. In January, 2026, Ecopetrol's lawsuit was not admitted and is pending to be remedied by Ecopetrol.

Tax Reviews

The Company operates in various jurisdictions and is subject to assessments by tax authorities in each of those jurisdictions, which can be complex and based on interpretations. The Company is currently in discussions with tax authorities for various assessments with respect to certain income tax deductions relating to exportation expenditures, transportation costs, VAT credits, municipal taxes, and other expenses. As at December 31, 2025, the Company has assessed a possible tax exposure of $96.2 million (2024: $90.9 million) relating to these assessments for taxes, interest, and penalties (the increase is mainly due to exchange rate effect resulting from the depreciation of the Colombian peso against the U.S. dollar). As at December 31, 2025, the carrying value of the tax liability provisions is $1.1 million (2024: $0.7 million). The increase is mainly due to the Company's decision to pay the 2020 self-withholding contingency corresponding to the months of January to November.

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 17, 2026:

	Number
Common shares	69,351,887
DSUs (1)	1,327,947
RSUs (2)	1,848,304

(1) DSUs represent a future right to receive Common Shares (or the cash equivalent), generally at the time of the holder's retirement, death or other cessation of service to the Company, subject to limited exceptions as agreed to by the holder of the DSU. Each DSU awarded by the Company approximates the fair market value of a Common Share at the time of the award. The value of a DSU increases or decreases as the price of the Common Shares fluctuates, thereby promoting alignment of interests between the DSU holder and shareholders. DSUs are settled in Common Shares issued from treasury or purchased on the open market, cash, or a combination thereof, as determined by the Compensation and Human Resources Committee of the board of directors of the Company (the "CHRC"), in its sole discretion. Only persons who hold the office of a director at the time of grant are entitled to receive DSUs.

(2) RSUs represent a right to receive Common Shares (or the cash equivalent) at a future date, subject to established vesting conditions. RSUs are granted with vesting conditions based on continued service and/or the achievement of corporate objectives. The value of an RSU increases or decreases as the price of the Common Shares fluctuates, thereby promoting the alignment of interests between the RSU holder and shareholders. RSUs are settled in Common Shares issued from treasury or purchased on the open market, cash, or a combination thereof, as determined by the CHRC, in its sole discretion. Vesting terms for RSUs are determined by the CHRC, in its sole discretion, and specified in the award agreement pursuant to which the RSU is granted.

Normal Course Issuer Bids ("NCIB")

On November 21, 2023, the Company launched an NCIB (the "**2023 NCIB**"), pursuant to which it was permitted to repurchase for cancellation up to 3,949,454 of its Common Shares, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules) as at November 8, 2023, during the 12-month period commencing on November 21, 2023, and ending on November 20, 2024.

The Company repurchased a total of 1,552,100 Common Shares under the 2023 NCIB for approximately $9.5 million prior to its expiration on November 20, 2024.

On July 15, 2025, the Company launched an NCIB (the "**2025 NCIB**"), pursuant to which it was permitted to repurchase for cancellation up to 3,502,962 of its Common Shares, representing approximately 5% of the Company's "public float" (as calculated in accordance with TSX rules) as at July 15, 2025, during the 12-month period commencing July 18, 2025, and ending July 17, 2026.

The average daily trading volume of the Common Shares (as calculated in accordance with the TSX rules) was 48,188 Common Shares over the period between January 1, 2025 and June 30, 2025. Consequently, daily purchases through the facilities of the TSX will be limited to 12,047 Common Shares, other than block purchase exceptions.

As at March 17, 2026, the Company had repurchased for cancellation a total of 716,100 Common Shares under the 2025 NCIB for approximately $3.4 million with an additional 2,786,862 Common Shares remaining available for repurchase under the 2025 NCIB.

Purchases under the NCIBs conducted by the Company have been or are being carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc., on behalf of Frontera, in accordance with an automatic share purchase plan and applicable regulatory requirements.

As a result of the announcement of the Arrangement, the Company intends to suspend purchases under the NCIB that are made pursuant to the Company's automatic securities purchase plan, and the Company is not aware of any material undisclosed information about itself.

Substantial Issuer Bid

On September 4, 2024, the Company's Board of Directors approved an SIB to repurchase from shareholders up to 3,375,000 Common Shares for cancellation at a purchase price of CAD$12.00 per share, totaling up to CAD$40.5 million (equivalent to $30.0 million) (the "**2024 SIB**"). The bid expired on October 17, 2024.

On October 22, 2024, the Company, in accordance with the terms and conditions of the 2024 SIB, took up and paid for 3,375,000 Common Shares (approximately 4.01% of the total number of Frontera's issued and outstanding Common Shares as at October 17, 2024) at a price of CAD$12.00 per Common Share, with an approximately 92% shareholder participation rate, and representing an aggregate purchase price of approximately CAD$40.5 million. Following the cancellation of the Common Shares repurchased under the 2024 SIB, approximately 80.78 million Common Shares remained issued and outstanding..

On December 16, 2024, the Company's Board of Directors approved an SIB to repurchase from shareholders up to 3,500,000 Common Shares for cancellation at a purchase price of CAD$12.00 per share, totaling up to CAD$42.0 million (equivalent to $30.0 million) (the "**January 2025 SIB**"). The January 2025 SIB expired on January 24, 2025.

On January 28, 2025, the Company announced that, in accordance with the terms and conditions of the January 2025 SIB, Frontera had taken up and paid for 3,500,000 Common Shares (approximately 4.33% of the total number of Frontera's issued and outstanding Common Shares as at January 24, 2025) at a price of CAD$12.00 per Common Share, representing an aggregate purchase price of approximately CAD$42.0 million. The January 2025 SIB had over 90% shareholder participation rate. After the cancellation of the Common Shares taken up and paid for by the Company under the January 2025 SIB, approximately 77.29 million Common Shares remained issued and outstanding.

On May 21, 2025, the Company's Board of Directors approved an SIB to repurchase from shareholders up to 7,583,333 Common Shares for cancellation at a purchase price of CAD$12.00 per share, totaling up to CAD$91.0 million (equivalent to $65.0 million) (the "**July 2025 SIB**"). The July 2025 SIB expired on July 10, 2025.

On July 15, 2025, the Company announced that, in accordance with the terms and conditions of the July 2025 SIB, Frontera had taken up and paid for 7,583,333 Common Shares (approximately 9.77% of the total number of Frontera's issued and outstanding Common Shares as at July 10, 2025) at a price of CAD$12.00 per Common Share, representing an aggregate purchase price of approximately CAD $91.0 million. The July 2025 SIB had a 92.6% participation and the tendered Common Shares were purchased on a pro rata basis. After the cancellation of the Common Shares taken up and paid for by the Company under the July 2025 SIB, approximately 70.06 million Common Shares were issued and outstanding.

Dividends

On March 7, 2024, the Company adopted a dividend policy that included an initial cash dividend of CAD$0.0625 per Common Share. This dividend payment to shareholders was designated as an "eligible dividend" under the Income Tax Act (Canada). The declaration and payment of any specific quarterly dividend remain subject to the discretion of the Company's Board of Directors.

The Company's dividends declared or paid during the year ended December 31, 2025, are presented below:

Declaration Date	Record Date	Payment Date	Dividend (C$/ Share)	Dividends Amount ($M)	Number of DRIP Shares [(1)]
March 7, 2024	April 2, 2024	April 16, 2024	0.0625	3,899	—
May 7, 2024	July 3, 2024	July 17, 2024	0.0625	3,858	626
August 6, 2024	October 2, 2024	October 16, 2024	0.0625	3,849	531
November 6, 2024	January 3, 2025	January 17, 2025	0.0625	3,502	1,073
March 10, 2025	April 7, 2025	April 16, 2025	0.0625	3,373	1,018
May 9, 2025	July 8, 2025	July 17, 2025	0.0625	3,543	808
August 12, 2025	October 2, 2025	October 16, 2025	0.0625	3,128	735
November 12, 2025	January 5, 2026	January 19, 2026	0.0625	3,128	338

[(1)] In connection with the adoption of the dividend policy, the Company adopted a Dividends Reinvestment Program ("DRIP"), which provides shareholders who are resident in Canada with the option to have cash dividends declared on their Common Shares automatically reinvested into additional Common Shares, without brokerage commissions or service charges.

In connection with the recently announced transaction with Parex, and considering the transaction's effective date (January 1, 2026), the Company has determined to suspend the declaration and payment of its quarterly dividend until the transaction is finalized.

8. RELATED-PARTY TRANSACTIONS

The following table provide the total balances outstanding, commitments, and transactional amounts with related parties as at December 31, 2025, and December 31, 2024, and for the three months and the year ended December 31, 2025, and 2024, respectively:

		December 31, 2025 and December 31, 2024			Three months ended December 31	Year ended December 31
($M)		Receivables from ODL Investment	Accounts Payable	Commitments	Purchases/Services	
ODL	2025	—	3,262	925	8,067	31,131
	2024	—	2,901	356	7,573	29,608

As at December 31, 2025, as part of the second lien of FPI Recapitalization Loan, a $5.0 million balance (December 31, 2024: $Nil) was acquired by funds controlled by GDA Luma Capital Management, LP (which itself is controlled by Gabriel de Alba, the Chair of the Board of Directors of Frontera).

9. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives, including, but not limited to: production; liquidity and financial; health, safety and environmental; exploration, new business and reserves growth; information security; and political risk. The impact of any risk may adversely affect, among other things, the Company's business, reputation, financial condition, results of operations and cash flows, which may affect the market price of its securities.

The Company has an enterprise risk management program that identifies, evaluates, prioritizes, monitors, and plans for risk across the organization and supports decision-making. This program identifies critical strategic risks related to people, assets, operations, the regulatory environment, health, safety and environment, liquidity, reputation, communities, and the political landscape, and seeks to systematically mitigate these risks to an acceptable level. In addition, the Company continuously monitors its risk profile as well as industry best practices.

During the third quarter of 2025, the board of directors of the Company approved a restructuring plan (the "**Restructuring Plan**"), as part of Frontera's ongoing focus on cost-savings, designed to simplify its corporate structure, through targeted reorganization initiatives that are designed to improve organizational and operational efficiencies, generating between $10 and $15 million expected savings in overhead going forward. The Company may encounter challenges in the execution of these restructuring efforts that could prevent it from recognizing the intended benefits of the Restructuring Plan or otherwise adversely affect its business, results of operations and financial condition. As a result of the Restructuring Plan, the Company has incurred and may continue to incur additional costs in the short-term, including cash expenditures for employee transition, notice period and severance payments, employee benefits and related costs. These additional expenditures could have the effect of reducing the Company's operating margins. The Restructuring Plan may result in other unintended consequences. If the Company experiences any of these adverse consequences, the Restructuring Plan may not achieve or sustain its intended benefits, or the benefits, even if achieved, may not be adequate to meet the Company's long-term profitability and operational expectations, which could adversely affect the Company's business, results of operations and financial condition.

See the "Liquidity and Capital Resources" section on page 35 for further details on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

See the disclaimer regarding forward-looking information on the front page of this MD&A.

The information above is not intended to describe all of the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risks and uncertainties that could affect the business and operations of the Company, please see the Company's AIF and the 2025 Annual Consolidated Financial Statements, copies of which are available on SEDAR+ at www.sedarplus.ca.

10. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The 2025 Annual Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part I of the CPA Canada Handbook-Accounting. A summary of the significant accounting policies applied is included in Note 3a of the 2025 Annual Consolidated Financial Statements. The Company has not early adopted any standards, interpretations or amendments that have been issued but are not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 3b of the 2025 Annual Consolidated Financial Statements, including management's evaluation of their impact and implementation progress.

The preparation of the 2025 Annual Consolidated Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, and to make estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss as well as the related disclosure of contingent assets and liabilities included in the 2025 Annual Consolidated Financial Statements. The Company evaluates its estimates on an ongoing basis.

The estimates are based on historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. These estimates form the basis for making judgments about the carrying value of assets and liabilities, as well as the reported amounts of revenues and other items.

Geopolitical instability, international conflicts, and related sanctions have contributed to and may continue to contribute to increased volatility in the global oil and gas markets. Following the February 2022 invasion by Russia of Ukraine, certain countries, including Canada, the United States and many European nations, have imposed numerous and varying levels of financial and trade sanctions against Russia, a major oil and gas producing state. In addition, other international disputes, including the recent conflict and ongoing instability in the Middle East, which is home to many of the world's biggest oil producers, have had and may continue to have wide-ranging consequences on the world economy and in particular the oil and gas industry. Most recently, Israel, together with the United States, conducted a major joint military operation in Iran, which triggered a military response from Iran against Israel and other countries in the region, including the United Arab Emirates, Bahrain and Qatar, as well as against U.S. targets in the Middle East. These matters have caused and may continue to cause increased volatility in the global supply of oil and natural gas, energy prices, and the market value of the securities of those companies which operate in the oil and gas industry, including the Company. Recent developments indicate heightened trade tensions between the United States and Colombia and elsewhere. During the year, the U.S. government enacted trade tariffs on numerous countries including Colombia and has more recently introduced a 10% global tariff rate. The Company may be adversely affected by the imposition of new tariffs, higher tariffs, or adverse developments in the diplomatic and commercial relations between the United States and Colombia or the United States and other countries, which may disrupt the Company's financial performance and operational stability. Additionally, given the unpredictable nature of international trade policies, there can be no assurance that future disputes will not arise or that they will be resolved favorably. The long-term implications of these trade tensions remain uncertain, and the Company continues to monitor these matters as they evolve.

To date, these events have not negatively impacted the Company's operations, and there have been no significant delays or direct security issues affecting the Company's operations, offices, or personnel. The long-term impacts of these conflicts and sanctions remain uncertain, the Company continues to monitor these types of situations as they evolve. This presents uncertainty and risk with respect to management's judgments, estimates, and assumptions used in the preparation of the 2025 Annual Consolidated Financial Statements.

The results of the economic downturn and any potential resulting direct and indirect impact to the Company have been considered in management's judgments and estimates as described above for the quarter-end; however, there could be further prospective material impacts in future periods. Actual results may therefore differ from these estimates under different assumptions or conditions. A summary of the critical accounting estimates and judgments made by management in the preparation of its financial information for the past two financial years is provided in Note 3c of the 2025 Annual Consolidated Financial Statements.

11. INTERNAL CONTROL

In accordance with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings* ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Interim Filings" on Form 52-109F1. This Certification requires that each "certifying officer" (as defined in NI 52-109) certify, among other things, that they, together with the other certifying officer(s), are responsible for establishing and maintaining disclosure controls and procedures ("**DC&P**") and internal control over financial reporting ("**ICFR**"), as those terms are defined in NI 52-109. The control framework used to design the Company's ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company's ICFR is designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements due to inherent limitations.

Management of the Company has evaluated the effectiveness of the Company's ICFR for the period beginning October 1, 2025, and ending December 31, 2025. Based on this assessment, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's ICFR was effective as at December 31, 2025.

There has been no change in the Company's ICFR during the period beginning on October 1, 2025, and ending on December 31, 2025, that has materially affected, or is reasonably likely to materially affect, its ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's DC&P is designed to provide reasonable assurance that material information relating to the Company is made known to the Company's certifying officers by others, particularly during the period in which the annual filings are being prepared, and that information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized, and reported within the time period specified in securities legislation.

Based on management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's DC&P was effective as at December 31, 2025.

12. FURTHER DISCLOSURES

Production Colombia Reporting by Block

The following table summarizes the average production Colombia before royalties from the Company's operations:

		Production				
Producing blocks		**Q4 2025**	**Q3 2025**	**Q4 2024**	**2025**	**2024**
Quifa	(bbl/d)	17,639	17,586	16,890	17,395	16,973
CPE-6	(bbl/d)	7,346	7,710	8,466	7,718	7,279
Guatiquia	(bbl/d)	5,007	5,145	5,690	5,164	5,660
Sabanero	(bbl/d)	1,711	1,781	2,384	2,004	1,076
VIM-1	(boe/d)	2,286	2,187	1,883	2,070	1,814
Cubiro	(bbl/d)	896	981	1,310	1,036	1,427
Cravoviejo	(bbl/d)	1,282	1,295	1,263	1,255	1,314
Other blocks	(boe/d)	2,165	2,249	2,770	2,369	3,080
Total production	**(boe/d)**	**38,332**	**38,934**	**40,656**	**39,011**	**38,623**

Net Production

Production volumes in this MD&A are reported on a Company's gross W.I. basis before royalties. The Company has reported the share of production retained by the government under the contract, as royalties paid in-kind in this MD&A.

The following table shows the average net production, after deduction of such royalties:

		Net Production				
					Year ended December 31	
Net Production from Continuing Operations:		**Q4 2025**	**Q3 2025**	**Q4 2024**	**2025**	**2024**
Net Producing blocks in Colombia						
Heavy crude oil	(bbl/d)	24,823	25,175	25,513	25,140	22,563
Light and medium crude oil combined	(bbl/d)	8,157	8,169	9,235	8,367	9,535
Conventional natural gas	(mcf/d)	5,261	4,406	2,633	3,773	3,278
Natural gas liquids	(boe/d)	1,369	1,404	1,498	1,405	1,546
Net production Colombia	**(boe/d)**	**35,272**	**35,521**	**36,708**	**35,574**	**34,219**
Production from Discontinued Operations:						
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	641	698	1,261	833	1,159
Net production Ecuador	**(bbl/d)**	**641**	**698**	**1,261**	**833**	**1,159**

Boe Conversion

The term “boe” is used in this MD&A. The use of boe may be misleading, particularly when presented in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip, and does not represent a value equivalency at the wellhead. In this MD&A, boe is expressed using the Colombian conversion standard of 5.7 Mcf to 1 bbl required by the Colombian Ministry of Mines and Energy.

Oil and Gas Information Advisories

Reported production levels may not be reflective of sustainable production rates and future production rates may differ materially from those reflected in this MD&A due to, among other factors, difficulties or interruptions encountered during the production of hydrocarbons.

Abbreviations

The following abbreviations are frequently used in the Company’s MD&A.

bbl	Oil barrels	**LNG**	Liquefied Natural Gas
bbl/d	Barrels of oil per day	**MMcf/d**	Millions of cubic feet per day
boe	Barrels of oil equivalent	**m3**	Cubic metre
boe/d	Barrels of oil equivalent per day	**Q**	Quarter
BSW	Basic sediment and water	**sqkm**	Square kilometre
bwpd	Barrels of water per day	**Tons**	Tonnes
COP	Colombian pesos	**TEU**	Twenty-foot Equivalent Unit
CAD$	Canadian dollars	**USD**	United States dollars
FX	Foreign exchange	**WTI**	West Texas Intermediate
ha	Hectare	**W.I.**	Working interest
MMbbl	Millions of oil barrels	**$**	U.S. dollars
MMboe	Millions of barrels of oil equivalent	**$M**	Thousands of U.S. dollars
Mbbl	Thousands of oil barrels	**$MM**	Millions of U.S. dollars
Mcf	Thousands cubic feet	**P1**	Proved reserves
mcf/d	Thousands cubic feet per day	**P2**	Probable reserves
LPG	Liquefied Petroleum Gas	**2P**	Proved reserves + Probable reserves