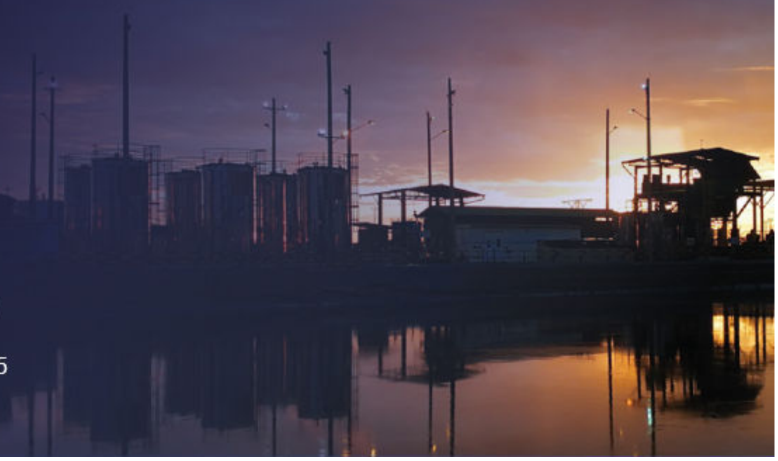

MANAGEMENT DISCUSSION & ANALYSIS

Aug 13, 2025
For the three and six months ended June 30, 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 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 Interim Condensed Consolidated Financial Statements and related notes for the three and six months ended June 30, 2025 and 2024 (the **"Interim 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 24.*

*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 in this MD&A includes, without limitation, statements regarding estimates and/or assumptions in respect of the oil price environment, potential health risks, the U.S. trade tariffs affecting on numerous countries including Colombia, the impact of the Russia-Ukraine conflict and the conflict in the Middle East, the ongoing validity of the licenses and agreements for the Corentyne block in Guyana and future discussions and legal processes involving the Government of Guyana related thereto, the expected impact of measures that the Company has taken and continues to take or may take in response to these events, the Company's goal of enhancing the value of its Common Shares and consideration forms of strategic initiatives and transactions in connection therewith, the timing of the payment of the dividend, expectations regarding the 2025 capital and production guidance, the completion and operational timing of the connection project between Puerto Bahia (as defined below) and Reficar (as defined below), and LPG joint venture, the water handling capacity at SAARA, the expected completion date for pre-drilling and drilling activities for the Guapo-1 exploratory well, 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 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 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.

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; any health security situation; 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; and the development and execution of projects.

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; measures the Company has taken and continues to take or may take in response to pandemics; the U.S. trade tariffs affecting on numerous countries including Colombia; the impact of the Russia-Ukraine conflict and the conflict in the Middle East; actions of the Organization of Petroleum Exporting Countries ("OPEC+"); 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 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 on receipt of government approvals; 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 Company and its joint venture partner'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. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q2 2025	Q1 2025	Q2 2024	Six months ended June 30 2025	Six months ended June 30 2024
Operational Results						
Heavy crude oil production [(1)]	(bbl/d)	27,535	27,167	24,839	27,352	24,119
Light and medium crude oil combined production [(1)]	(bbl/d)	11,127	10,998	12,583	11,062	12,582
Total crude oil production	(bbl/d)	38,662	38,165	37,422	38,414	36,701
Conventional natural gas production [(1)]	(mcf/d)	3,118	2,274	4,019	2,696	3,654
Natural gas liquids production [(1)]	(boe/d) [(3)]	1,846	1,913	1,785	1,879	1,711
Total production [(2)]	(boe/d) [(3)]	41,055	40,477	39,912	40,766	39,053
Total inventory balance	(bbl)	1,142,536	911,886	1,319,189	1,142,536	1,319,189
Brent price reference	($/bbl)	66.71	74.98	85.03	70.81	83.42
Produced crude oil and gas sales [(4)]	($/boe)	63.04	68.42	78.31	65.81	77.23
Purchased crude net margin [(4)(5)]	($/boe)	(3.53)	(3.81)	(2.62)	(3.67)	(2.81)
Oil and gas sales, net of purchases [(4)(5)]	($/boe)	59.51	64.61	75.69	62.14	74.42
Gain (loss) on oil price risk management contracts [(6)(7)]	($/boe)	0.15	(1.35)	(1.32)	(0.62)	(1.30)
Royalties [(6)]	($/boe)	(0.80)	(1.00)	(2.01)	(0.90)	(1.83)
Net sales realized price [(4)(5)]	($/boe)	58.86	62.26	72.36	60.62	71.29
Production costs (excluding energy costs), net of realized FX hedge impact [(4)]	($/boe)	(9.01)	(10.04)	(10.79)	(9.52)	(10.51)
Energy costs, net of realized FX hedge impact [(4)]	($/boe)	(4.71)	(5.38)	(4.74)	(5.04)	(5.01)
Transportation costs, net of realized FX hedge impact [(4)(5)]	($/boe)	(11.62)	(12.32)	(11.07)	(11.96)	(11.27)
Operating netback per boe [(4)(5)]	($/boe)	33.52	34.52	45.76	34.10	44.50
Financial Results						
Oil & gas sales, net of purchases [(8)]	($M)	170,943	197,975	217,130	368,918	417,904
Gain (loss) on oil price risk management contracts [(7)]	($M)	431	(4,141)	(3,796)	(3,710)	(7,285)
Royalties	($M)	(2,304)	(3,060)	(5,774)	(5,364)	(10,280)
Net sales [(8)]	($M)	169,070	190,774	207,560	359,844	400,339
Net (loss) income [(9)]	($M)	(455,212)	27,524	(2,846)	(427,688)	(11,349)
Per share – basic	($)	(5.89)	0.35	(0.03)	(5.50)	(0.13)
Per share – diluted	($)	(5.89)	0.34	(0.03)	(5.50)	(0.13)
General and administrative	($M)	14,279	13,571	12,928	27,850	26,484
Outstanding Common Shares	Number of Shares	77,295,478	77,294,460	84,253,816	77,295,478	84,253,816
Operating EBITDA [(8)]	($M)	76,073	83,458	110,321	159,531	207,569
Cash provided by operating activities	($M)	41,786	70,137	149,787	111,923	215,403
Capital expenditures [(8)]	($M)	59,402	46,711	80,198	106,113	149,579
Cash and cash equivalents – unrestricted	($M)	184,860	170,094	180,659	184,860	180,659
Restricted cash short and long-term [(10)]	($M)	12,679	29,738	34,419	12,679	34,419
Total cash [(10)]	($M)	197,539	199,832	215,078	197,539	215,078
Total debt and lease liabilities [(10)]	($M)	535,346	505,486	523,994	535,346	523,994
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(11)]	($M)	353,764	409,675	426,004	353,764	426,004
Net debt (excluding Unrestricted Subsidiaries) [(11)]	($M)	204,671	290,732	283,651	204,671	283,651

(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 40 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 40 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 24 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 24 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 15 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 24 for further details.
(9) Net (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 24 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 Sociedad Portuaria Puerto Bahia S.A ("**Puerto Bahia**"). Refer to the "Liquidity and Capital Resources" section on page 31 for further details.

Performance Highlights

Frontera's corporate strategy focuses on maximizing value through its portfolio of energy and infrastructure related assets via its three core businesses:

- **Colombian and Ecuador Upstream Onshore**: cash flow-focused production and reserves management from large, long-life onshore Colombia and Ecuador operations with a strong commitment to responsible and sustainable business practices;
- **Infrastructure Colombia**: profitable and significant Colombian infrastructure footprint uniquely positioned to capture growth from emerging opportunities across the value chain providing stable, long-term revenue streams; and
- **Guyana Exploration**: offshore Guyana opportunity for a potential Maastrichtian-based, stand-alone commercial development, with upside and future opportunities in deeper geological zones.

Second Quarter of 2025

Frontera's second quarter financial and operating results demonstrate the decisive steps that the Company is taking to deliver stakeholder value, maintain financial and operational flexibility, and reduce leverage over the long-term. The Company increased its total production quarter over quarter driven by increased processing capacity at SAARA, investments in new flow lines in the heavy oil fields, a successful well intervention program within the light and medium blocks and new commercialized volumes of natural gas production from the VIM-1 block. Despite some natural decline of natural gas liquids and Ecuador production.

Despite a volatile global macro-economic and oil market backdrop, Frontera continued to execute on its strategic goals and priorities across its businesses in the second quarter delivering strong operating results and completing significant value-generating initiatives for its shareholders and bondholders. The Company generated $76.1 million in Operating EBITDA, produced $27.1 million of Adjusted Infrastructure EBITDA, and maintained a strong balance sheet, finishing the quarter with a total cash balance of $197.5 million while reducing its upstream net debt by 30%.

During the quarter, the Company continued to prioritize operational improvements, reducing capital spending and cost and process efficiencies across its business, delivering a 10.3% decrease in production costs quarter-over-quarter driven by fewer well interventions and the implementation of new production technologies. The Company also reduced its transportation costs by 5.7% quarter-over-quarter driven by higher domestic wellhead sales.

Consistent with its strategy, following the end of the quarter, the Company announced it had reached an agreement to divest its interest in the Company's non-core Perico and Espejo fields in Ecuador. This transaction is consistent with the Company's strategy of maximizing value over volumes, and supports a stronger focus on its higher-impact Colombian upstream operations. As a result, the Company is adjusting its 2025 production guidance to account for the impact of Ecuador sale to 39,500 to 41,000 boe/d. In light of the current oil price environment, the Company is also adjusting its capital expenditures guidance downwards, by approximately $20 million, reducing its development facilities Capex to $45 - 65 million and exploration Capex to $25 - 35 million, reflecting its disciplined approach to capital spending and ability to identify ongoing operational efficiencies. Additionally, the Company is providing Operating EBITDA guidance at a $70/bbl Brent Price with a target of between $320 - $360 million and revising its Adjusted Infrastructure EBITDA guidance to between $110 - 125 million.

In its standalone and growing Colombia infrastructure business, which includes the Company's interest in ODL, generated an Adjusted Infrastructure EBITDA of $27.1 million. At Puerto Bahia, the Reficar connection was completed by the end of the quarter and now the Company's efforts shift to the first transported volumes which are expected during the third quarter of 2025. Strategic investments in the port, including the LPG JV with Empresas Gasco, are progressing on schedule. The port is also pursuing additional investment opportunities that leverage its facilities and infrastructure for sustainable long-term growth.

With respect to the Guyana exploration license, the Company evaluated the Corentyne E&E asset's recoverability given the conduct and communications of Government of Guyana (the "**GoG**"), and its unwillingness to recognize the rights of Frontera Energy Guyana Corp.'s ("**Frontera Guyana**") and CGX Resources Inc.'s ("**CGX Resources**", and together with Frontera Guyana, the "**Joint Venture**") 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, and the Corentyne E&E asset's carrying value as of June 30, 2025 is $Nil (December 31, 2024 $431.9 million).

This accounting treatment reflects the current operational limitations and does not constitute an acknowledgment by the Joint Venture of any diminution in its legal position regarding its rights under the licenses and agreements and applicable law regarding the Corentyne block. The Joint Venture, along with its stakeholders, remain committed to protecting and enforcing their contractual and legal rights through all appropriate means. According to IFRS standards, impairment expense can be reversed in the future if subsequent circumstances indicate changes in the recoverable amount of the asset.

The Company prioritized returning capital to all investors via its successful $80 million tender and consent solicitation of the 2028 Unsecured Notes (as defined below) and, subsequent to the quarter a C$91 million substantial issuer bid ("**SIB**"), the largest in the Company's history, with an over 90% consistent participation rate in the SIBs, the Company's capital distribution strategy has proven effective and well received by the shareholders. The Company also declared a quarterly dividend of C$0.0625 per share, or approximately $3.5 million in aggregate, and initiated a non-course issuer bid program. Over the last twelve-months, Frontera has returned over $144 million to shareholders via dividends and share repurchases while also reducing its 2028 Unsecured Notes (as defined below) by over 20%. These efforts underscore the success of the Company's return of capital focus to its stakeholders.

The Company will continue to consider similar investor-focused initiatives in 2025 and beyond, including additional dividends, distributions, share or bond buybacks, based on the overall results of the businesses, oil prices and cash flow generation. Additionally, the Company will consider all options to enhance the value of its common shares, and in so doing may consider other strategic initiatives or transactions.

Financial and Operational Results

- Production averaged 41,055 boe/d in the second quarter of 2025 (consisting of 27,535 bbl/d of heavy crude oil, 11,127 bbl/d of light and medium crude oil combined, 3,118 mcf/d of conventional natural gas and 1,846 boe/d of natural gas liquids), compared with 40,477 boe/d in the prior quarter (consisting of 27,167 bbl/d of heavy crude oil, 10,998 bbl/d of light and medium crude oil combined, 2,274 mcf/d of conventional natural gas and 1,913 boe/d of natural gas liquids), and compared with 39,912 boe/d in the second quarter of 2024 (consisting of 24,839 bbl/d of heavy crude oil, 12,583 bbl/d of light and medium crude oil combined, 4,019 mcf/d of conventional natural gas and 1,785 boe/d of natural gas liquids).
- Cash provided by operating activities was $41.8 million in the second quarter of 2025, compared with $70.1 million in the prior quarter, and $149.8 million in the second quarter of 2024. The Company reported a total cash position of $197.5 million, including $12.7 million of restricted cash, as at June 30, 2025, compared with a total cash position of $199.8 million, including $29.7 million of restricted cash, as at March 31, 2025, and $215.1 million, including $34.4 million of restricted cash, as at June 30, 2024.
- The Company recorded a net loss(1) of $455.2 million, net of a non-cash impairment expenses of $477.0 million ($5.89/share(2)) in the second quarter of 2025, compared with a net income(1) of $27.5 million ($0.34/share(2)) in the prior quarter and a net loss(1) of $2.8 million ($0.03/share(2)) in the second quarter of 2024.
- Capital expenditures were $59.4 million in the second quarter of 2025, compared with $46.7 million in the prior quarter and $80.2 million in the second quarter of 2024.
- Operating EBITDA was $76.1 million in the second quarter of 2025, compared with $83.5 million in the prior quarter and $110.3 million in the second quarter of 2024.
- Operating netback was $33.52/boe in the second quarter of 2025, compared with $34.52/boe in the prior quarter and $45.76/boe in the second quarter of 2024.
- Infrastructure Colombia Segment (as defined below) income was $14.3 million in the second quarter of 2025, compared with $15.3 million in the prior quarter and $14.6 million in the second quarter of 2024.
- Adjusted Infrastructure EBITDA in the second quarter of 2025 was $27.1 million, compared with $28.6 million in the prior quarter and $27.8 million in the second quarter of 2024.
- Puerto Bahia liquid volumes handled during the second quarter of 2025 were 53,280 bbl/d, compared with 51,579 bbl/d in the prior quarter and 61,798 bbl/d in the second quarter of 2024. Puerto Bahia revenues were $11.2 million in the second quarter of 2025, compared with $9.9 million in the prior quarter and $11.2 million in the second quarter of 2024.
- ODL volumes transported were 235,804 bbl/d in the second quarter of 2025, compared with 236,387 bbl/d in the prior quarter of 2024, and 249,196 bbl/d in the second quarter of 2024.

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

(2) Per Common Share on a diluted basis.

2. GUIDANCE

The Company is adjusting its 2025 production guidance to reflect its Colombian operations only, now targeting 39,500 to 41,000 boe/d, following the divestment of its non-core assets in Ecuador. The Company is also revising its capital expenditures guidance downwards by approximately $20 million, reducing its development facilities Capex to $45 - 65 million and exploration Capex to $25 - 35 million. These changes reflect on the Company's disciplined approach to capital spending and ability to identify ongoing operational efficiencies. Additionally, the Company is providing Operating EBITDA guidance at a $70/bbl Brent Price targeting between $320 - $360 million and revising its Adjusted Infrastructure EBITDA guidance targeting between $110 - 125 million.

The following table reports the Company's actual results for the six months ended June 30, 2025:

Guidance Metrics	Unit	2025 Original Guidance	Actual	2025 Updated Guidance (excluding Ecuador)
Average Daily Production [1]	boe/d	41,000 - 43,000	40,766	39,500 - 41,000
Production Costs [2][4]	$/boe	8.75 - 9.25	9.52	8.75 - 9.25
Energy Costs [2][4]	$/boe	5.25 - 5.75	5.04	5.25 - 5.75
Transportation Costs [3][4]	$/boe	12.50 - 13.00	11.96	12.50 - 13.00
Operating EBITDA [5] at $75/bbl [6]	$MM	370 - 415		
Operating EBITDA [5] at $70/bbl [7]	$MM		159.5	320 - 360
Adjusted Infrastructure EBITDA [5]	$MM	115 - 130	55.7	110 - 125
Development Drilling	$MM	100 - 110	60.9	100 - 110
Development Facilities	$MM	60 - 80	23.8	45 - 65
Colombia and Ecuador Development	$MM	160 - 190	84.7	145 - 175
Colombia and Ecuador Exploration	$MM	30 - 40	12.2	25 - 35
Other [8]	$MM	10 - 15	1.3	10 - 15
Total Colombia & Ecuador Capex	$MM	200 - 245	98.2	180 - 225
Guyana Exploration	$MM	1 - 3	0.4	1 - 3
Colombia Infrastructure	$MM	15 - 20	7.5	15 - 20
Total Capital Expenditures [5]	$MM	216 - 268	106.1	196 - 248

2025 Additional Estimates Sensitives

Brent Crude Oil Price ($/bbl)	Unit	$65	$75	$85
Consolidated Operating EBITDA	$MM	270 - 315	370 - 415	460 - 505

[1] The Company's 2025 original and updated average production guidance range 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 24 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 24 for further details.
[6] 2025 Original Guidance Operating EBITDA calculated at Brent between $75/bbl and COP/USD exchange rate of 4,250:1.
[7] 2025 Updated Guidance Operating EBITDA calculated at Brent between $70/bbl and COP/USD exchange rate of 4,150:1.
[8] Other includes HSEQ activities and new field production technologies.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia and Ecuador. Refer to the "Further Disclosures" section on page 40 for details of the Company's net production:

		Production				
					Six months ended June 30	
Producing blocks in Colombia		**Q2 2025**	**Q1 2025**	**Q2 2024**	**2025**	**2024**
Heavy crude oil	(bbl/d)	27,535	27,167	24,839	27,352	24,119
Light and medium crude oil combined	(bbl/d)	9,850	9,531	10,928	9,691	11,015
Conventional natural gas	(mcf/d)	3,118	2,274	4,019	2,696	3,654
Natural gas liquids	(boe/d)	1,846	1,913	1,785	1,879	1,711
Total production Colombia	**(boe/d)**	**39,778**	**39,010**	**38,257**	**39,395**	**37,486**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,277	1,467	1,655	1,371	1,567
Total production Ecuador	**(bbl/d)**	**1,277**	**1,467**	**1,655**	**1,371**	**1,567**
Total production	**(boe/d)**	**41,055**	**40,477**	**39,912**	**40,766**	**39,053**

Colombia

For the three months ended June 30, 2025, production in Colombia increased by 768 boe/d compared to the previous quarter. Heavy crude oil production increased by 1%, mainly due to increased processing capacity at SAARA and investments in new flow lines in the Cajua field. Light and medium crude oil combined production, increased by 3%, driven by a successful well intervention program. Conventional natural gas production increase by 37% as a result of new commercialized volumes of natural gas from the VIM-1 block. Natural gas liquids production decreased 4%, primarily as a result of natural decline.

Production in Colombia for the three and six months ended June 30, 2025 compared to the same periods of 2024, increased by 1,521 boe/d and 1,909 boe/d, respectively, mainly due to the following: (i) heavy crude oil increases by 2,696 bbl/d and 3,233 bbl/d, respectively, resulting from the successful development drilling campaigns in the CPE-6, Sabanero and Quifa blocks, the reactivation of wells in the Sabanero block, water facilities in the CPE-6 block, increased water processing capacity at SAARA, which supports production levels from the Quifa block, (ii) natural gas liquids production increased by 3% and 10%, respectively, primarily from the VIM-1 block, as a result of the development of facilities for surface gas compression and handling systems. These gains were partially offset by (iii) decreases in light and medium crude oil combined production by 10% and 12%, respectively, and in conventional natural gas production by 22% and 26%, respectively, as a result of natural decline.

Ecuador

Production of light and medium crude oil combined for the three and six months ended June 30, 2025 decreased by 23% and 13% respectively, compared to the same periods of 2024, primarily due to natural reservoir decline. Compared to the prior quarter, production decreased by 13% due to natural decline.

Production Reconciled to Sales Volumes

The following table reconciles the Company's 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.

					Six months ended June 30	
		Q2 2025	**Q1 2025**	**Q2 2024**	**2025**	**2024**
Production	(boe/d)	**41,055**	**40,477**	**39,912**	**40,766**	**39,053**
Royalties in-kind Colombia	(boe/d)	(3,484)	(3,802)	(4,871)	(3,640)	(4,441)
Royalties in-kind Ecuador [(1)]	(boe/d)	(327)	(420)	(536)	(373)	(488)
Net production	(boe/d)	**37,244**	**36,255**	**34,505**	**36,753**	**34,124**
Oil inventory draw (build)	(boe/d)	(2,534)	1,307	(444)	(624)	(1,334)
Overlift (Settlement)	(boe/d)	—	(9)	—	(4)	—
Volumes purchased	(boe/d)	7,896	8,088	6,830	7,991	7,592
Other inventory movements [(2)]	(boe/d)	(2,883)	(2,701)	(2,797)	(2,794)	(2,629)
Sales volumes	(boe/d)	**39,723**	**42,940**	**38,094**	**41,322**	**37,753**
Sale of volumes purchased	(boe/d)	(8,155)	(8,896)	(6,571)	(8,523)	(6,900)
Sales volumes, net of purchases	(boe/d)	**31,568**	**34,044**	**31,523**	**32,799**	**30,853**
Oil sales volumes	(bbl/d)	31,062	33,697	30,816	32,372	30,212
Conventional natural gas sales volumes	(mcf/d)	2,884	1,978	4,030	2,433	3,654
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**31,568**	**34,044**	**31,523**	**32,799**	**30,853**
Inventory balance						
Colombia [(3)]	(bbl)	629,147	392,821	758,794	629,147	758,794
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	33,189	38,865	80,195	33,189	80,195
Inventory ending balance	**(bbl)**	**1,142,536**	**911,886**	**1,319,189**	**1,142,536**	**1,319,189**

(1) The Company reports the share of production retained by the government of Ecuador as royalties paid in kind.

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

(3) Includes 0.49 MMbbl of oil produced and 0.14 MMbbl of diluent in the second quarter of 2025, 0.22 MMbbl of oil produced and 0.17 MMbbl of diluent in the first quarter of 2025, and 0.41 MMbbl of oil produced and 0.35 MMbbl of diluent in the second quarter of 2024.

For second quarter of 2025, sales volumes, net of purchases, decreased by 7% compared with the prior quarter, mainly due to inventory drawdown during first quarter of 2025. Compared with the same quarter of 2024, sales volumes, net of purchases, were largely consistent. For the six months ended June 30, 2025, sales increased by 6%, compared with the same period of 2024, due to inventory drawdown and higher production.

Realized and Reference Prices

		Q2 2025	Q1 2025	Q2 2024	Six months ended June 30 2025	Six months ended June 30 2024
Reference price						
Brent [1]	($/bbl)	66.71	74.98	85.03	70.81	83.42
Average realized prices						
Realized oil price, net of purchases [2]	($/bbl)	59.93	64.95	76.66	62.53	75.27
Realized conventional natural gas price	($/mcf)	5.93	5.61	5.88	5.80	6.05
Net sales realized price						
Produced crude oil and gas sales [3]	($/boe)	63.04	68.42	78.31	65.81	77.23
Purchased crude net margin [2][3]	($/boe)	(3.53)	(3.81)	(2.62)	(3.67)	(2.81)
Oil and gas sales, net of purchases [3]	($/boe)	59.51	64.61	75.69	62.14	74.42
Gain (loss) on oil price risk management contracts [4] [5]	($/boe)	0.15	(1.35)	(1.32)	(0.62)	(1.30)
Royalties [4]	($/boe)	(0.80)	(1.00)	(2.01)	(0.90)	(1.83)
Net sales realized price [3]	**($/boe)**	**58.86**	**62.26**	**72.36**	**60.62**	**71.29**

(1) Frontera's weighted average Brent price for the three and six months ended June 30, 2025, was $67.17/bbl and $70.93/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 24 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 24 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 15 for further details.

The average Brent benchmark oil price during the three and six months ended June 30, 2025, decreased by 22% and 15%, respectively, compared to the same periods of 2024. Compared with the first quarter of 2025, the average Brent benchmark oil price decreased by 11%. The decrease in crude oil prices in 2025 compared with the same periods in 2024 was mainly due to: (i) OPEC+ accelerated unwinding of production cuts in the second quarter of 2025, which increased global oil supply, alongside additional output from Brazil, Argentina and Canada; (ii) tariff negotiations between the EU and Canada, China, Europe and Latin America, which have negatively affected the market demand sentiment; and (iii) a lower than anticipated war risk premium, which has not yet materialized. Although the Brent benchmark has decreased, Frontera oil price differentials have become narrower due to a strengthening of midsour crude oil.

Compared with the prior quarter, the Company's net realized sales price decreased 5%. The decrease was primarily driven by a lower Brent benchmark oil price, which was partially offset by stronger oil price differentials, the realized gain from oil price risk management contracts and lower royalties paid in cash.

For the three and six months ended June 30, 2025, the Company's net sales realized price decreased by $13.50/boe and $10.67/boe, respectively, compared to the same periods of 2024. The decrease was primarily driven by a lower Brent benchmark oil price and increases of purchased crude net margin due to higher dilution cost, partially offset by the positive cash settlement received from oil price risk management contracts, cash royalties paid and better oil price differentials.

Operating Netback

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

	Q2 2025		Q1 2025		Q2 2024	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	169,070	58.86	190,774	62.26	207,560	72.36
Production costs (excluding energy costs), net of realized FX hedge impact (1)(2)(3)	(33,647)	(9.01)	(36,592)	(10.04)	(39,198)	(10.79)
Energy costs, net of realized FX hedge impact (1)(2)(4)	(17,591)	(4.71)	(19,584)	(5.38)	(17,227)	(4.74)
Transportation costs, net of realized FX hedge impact (1)(2)(4)(5)	(39,393)	(11.62)	(40,185)	(12.32)	(34,753)	(11.07)
Operating Netback (1)(2)(6)	**78,439**	**33.52**	**94,413**	**34.52**	**116,382**	**45.76**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases (7)		31,568		34,044		31,523
Production (8)		41,055		40,477		39,912
Net production (9)		37,244		36,255		34,505

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 for further details.

(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 for further details.

(3) Includes $43 thousand, $Nil, and a gain of $2.2 million from realized FX hedge attributable to production costs for the second quarter of 2025, the first quarter of 2025, and the second quarter of 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 15 for further details.

(4) Includes $Nil, $Nil, and a gain of $0.8 million from realized FX hedge attributable to energy costs for the second quarter of 2025, the first quarter of 2025, and the second quarter of 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 15 for further details.

(5) Includes $Nil, $Nil, and a gain of $0.6 million from realized FX hedge attributable to transportation costs for the second quarter of 2025, the first quarter of 2025, and the second quarter of 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 15 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" section on page 6 for further details.

(9) Refer to the "Further Disclosures" section on page 40 for further details.

The Company's operating netback for the second quarter of 2025 was $33.52/boe, a decrease from $45.76/boe in the same quarter of 2024, mainly attributable to lower a Brent benchmark oil price. Compared to the first quarter of 2025, operating netback decreased by $1.00/boe, from $34.52/boe to $33.52/boe. Despite a $8.27/bbl decrease in the Brent benchmark oil price, the Company partially offset the lower netback through: (i) stronger oil price differentials, (ii) a reduction in production costs (excluding energy costs), net of realized FX hedge impact, mainly as a result of a reduction of well intervention activities and the adoption of new field production technologies, (iii) lower energy costs, net of realized FX hedge impact, driven by lower market prices, and (iv) lower transportation costs, due to reduced transported volumes, primarily resulting from improved domestic wellhead sales.

The following table provides a summary of the Company's netbacks for the six months ended June 30, 2025, and 2024:

	Six months ended June 30			
	2025		2024	
	$M	($/boe)	$M	($/boe)
Net sales realized price [1]	359,844	60.62	400,339	71.29
Production costs (excluding energy costs), net of realized FX hedge impact [1][2][3]	(70,239)	(9.52)	(74,700)	(10.51)
Energy costs, net of realized FX hedge impact [1][2][4]	(37,175)	(5.04)	(35,614)	(5.01)
Transportation costs, net of realized FX hedge impact [1][2][4][5]	(79,578)	(11.96)	(69,970)	(11.27)
Operating Netback [1][2][6]	**172,852**	**34.10**	**220,055**	**44.50**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases [7]		32,799		30,853
Production [8]		40,766		39,053
Net production [9]		36,753		34,124

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 for further details.

(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 for further details.

(3) Includes $43 thousand and a gain of $3.5 million from realized FX hedge attributable to production costs for the six months ended June 30, 2025, and 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 15 for further details.

(4) Includes $Nil and a gain of $1.4 million from realized FX hedge attributable to energy costs for the six months ended June 30, 2025, and 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 15 for further details.

(5) Includes $Nil and a gain of $1.0 million from realized FX hedge attributable to transportation costs for the six months ended June 30, 2025, and 2024, respectively. See "Gain (loss) on Risk Management Contracts" on page 15 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" section on page 6 for further details.

(9) Refer to the "Further Disclosures" section on page 40 for further details.

Operating netback for the six months ended June 30, 2025, was 34.10/boe compared to 44.50/boe in the same period of 2024. The changes were attributed to: (i) 15% decrease in net sales realized prices; (ii) increased transportation costs mainly due to the regular annual increase in transportation tariffs; and (iii) reduced production costs (excluding energy costs), net of realized FX hedge impact, mainly as a result of a reduction of well intervention activities and the adoption of new field production technologies. Energy costs, net of realized FX hedge impact, remained consistent within the periods.

Sales

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Produced crude oil sales	179,523	222,487	388,153	429,664
Purchased crude net margin [1][2]	(10,138)	(7,516)	(21,790)	(15,785)
Conventional natural gas sales	1,558	2,159	2,555	4,025
Oil and gas sales, net of purchases [3]	170,943	217,130	368,918	417,904
Gain (loss) on oil price risk management contracts [4]	431	(3,796)	(3,710)	(7,285)
Royalties	(2,304)	(5,774)	(5,364)	(10,280)
Net sales [1]	**169,070**	**207,560**	**359,844**	**400,339**
Net sales realized price ($/boe) [5]	58.86	72.36	60.62	71.29

(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 24 for further details.

(4) Includes put premiums paid for expired positions. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 15 for further details.

(5) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 for further details.

Oil and gas sales, net of purchases, decreased by $46.2 million and $49.0 million for the three and six months ended June 30, 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 8 for further details on price changes) and a higher purchased crude net margin. The negative impact was partially offset by the additional volumes produced and improved oil price differentials.

Net sales for the three and six months ended June 30, 2025, decreased by $38.5 million and $40.5 million, respectively, compared with the same periods of 2024. The following table describes the various factors that impacted net sales:

	Three months ended June 30	Six months ended June 30
($M)	**2025-2024**	**2025-2024**
Net sales for the period ended June 30, 2024	207,560	400,339
Decreased due to 21% lower oil and gas price (YTD 17% lower)	(46,425)	(68,995)
Increase due to variance of total produced volumes sold	238	20,009
Decrease in royalties	3,470	4,916
Decrease in oil price risk management contracts, net [1]	4,227	3,575
Net sales for the period ended June 30, 2025	**169,070**	**359,844**

[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 15 for further details.

Oil and Gas Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Transportation costs	38,701	34,917	78,250	70,112
Production costs (excluding energy costs)	32,367	41,401	68,046	78,240
Energy costs	17,591	17,997	37,175	36,965
Trunkline costs and others	519	—	2,519	—
Inventory valuation	(6,817)	(1,019)	(5,061)	(4,941)
Post-termination costs	(406)	(364)	(109)	186
Total oil and gas operating costs	**81,955**	**92,932**	**180,820**	**180,562**

During the three and six months ended June 30, 2025, total oil and gas operating costs decreased by $11.0 million and increased $0.3 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 and six months ended June 30, 2025, transportation costs increased by 11% and 12%, respectively, compared with the same periods of 2024, primarily due to higher volumes produced and transported, and the regular annual increase in transportation tariffs.
- Production costs (excluding energy costs) for the three and six months ended June 30, 2025, decreased by 22% and 13%, respectively, compared with the same periods of 2024, primarily due to lower well services activities and the implementation of new field production technologies.
- Energy costs for three months ended June 30, 2025, decreased by 2% compared with the same period of 2024, mainly due to lower market prices. For the six months ended June 30, 2025, energy costs increased by 1% compared with the same period of 2024.
- 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. The Company expects to recover a portion of these costs through claims under its material damages and third-party liability insurance policies. In addition, for the three and six months ended June 30, 2025, includes external road maintenance expenses associated with damage caused by the heavy rainy season.
- Inventory valuation for the three and six months ended June 30, 2025, changed by $5.8 million and $0.1 million, respectively, compared to the same periods of 2024, primarily due to increased inventory levels associated with recovery-related operational activity.
- Post-termination obligations for the three and six months ended June 30, 2025, resulted in recoveries of $0.4 million and $0.1 million, respectively. These were primarily due to cost efficiencies in executing activities related to returned blocks, partially offset by costs associated with the relinquishment of the Rio Ariari block in Colombia.

Cost of Diluent and Oil Purchased

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Cost of diluent and oil purchased (1)	58,609	55,153	127,469	113,012

(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 24 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 and six months ended June 30, 2025, the cost of diluent and oil purchases increased by $3.5 million and $14.5 million, respectively, compared to the same periods of 2024. These increases were primarily driven by higher heavy crude oil production, which increased demand for diluent and fuel used for energy, and a decrease in light and medium crude oil production used in refining operations, resulting in increased purchase requirements.

Royalties

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Royalties Colombia	1,965	5,299	4,753	9,693
Royalties Ecuador	339	475	611	587
Royalties	**2,304**	**5,774**	**5,364**	**10,280**

Royalties include cash payments for PAP (as defined below), royalty payments, and payments to previous owners of certain blocks in Colombia and Ecuador. For the three and six months ended June 30, 2025, royalties decreased by $3.5 million and $4.9 million, respectively compared with the same periods of 2024, mainly due to lower WTI oil benchmark price.

Colombia Royalties PAP

The Company makes high price clause participation (“**PAP**”) payments to Ecopetrol S.A. (“**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.

					Six months ended June 30	
		Q2 2025	**Q1 2025**	**Q2 2024**	**2025**	**2024**
PAP in kind	(bbl/d)	379	697	2,050	537	1,688
PAP in cash	(bbl/d)	204	262	402	233	389
PAP	**(bbl/d)**	**583**	**959**	**2,452**	**770**	**2,077**
% Production		**1.4 %**	**2.4 %**	**6.1 %**	**1.9 %**	**5.3 %**

Depletion, Depreciation and Amortization

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Depletion, depreciation and amortization	60,600	63,188	127,994	129,000

For the three and six months ended June 30, 2025, depletion, depreciation, and amortization expense (“**DD&A**”) decreased by 4% and 1%, respectively, compared to the same periods of 2024, primarily due to lower production in light and medium crude oil and conventional natural gas assets, and the expiration of the Abanico block production contract in October 2024.

Impairment Expense, Exploration Expenses and Others

	Three months ended June 30		Six months ended June 30	
($M)	2025	2024	2025	2024
Impairment expense of:				
Properties, plant and equipment	31,268	—	31,268	—
Exploration and evaluation assets	446,148	—	446,383	—
Other	(456)	392	443	1,419
Total impairment expense	476,960	392	478,094	1,419
Exploration expenses of:				
Geological and geophysical costs, and other	466	404	938	814
Total exploration expenses	466	404	938	814
Expense (recovery) of asset retirement obligations	151	45	526	(997)
Impairment expense, exploration expenses and other	**477,577**	**841**	**479,558**	**1,236**

Properties, plant and equipment

During the three and six months ended June 30, 2025, the Company recorded an impairment charge of $31.3 million and $31.3 million, respectively (2024: $Nil and $Nil). At the end of the second quarter, the Company identified a change in the intended of use of the assets related to the Perico block in Ecuador. As a result, the recoverable amount was reassessed in accordance with IAS 36, recognizing impairment charges of $31.3 million and $31.3 million, respectively (2024: $Nil and $Nil).

Exploration and Evaluation Assets

During the three and six months ended June 30, 2025, the Company recorded an impairment charge of $446.1 million and $446.4 million, respectively (2024: $Nil and $Nil), mainly related to the impairment of Corentyne block (for further information, please refer to “Critical Judgments in Applying Accounting Policies” section of the Interim Financial Statements for the three and six months ended June 30, 2025). In addition, during the end of the second quarter, the Company identified a change in the intended of use of the assets related to the Espejo block in Ecuador. As a result, the recoverable amount was reassessed in accordance with IAS 36, recognizing an impairment charge of $13.8 million.

Other

During the three months ended June 30, 2025, the Company recognized a reversal of other impairment expenses of $0.5 million, mainly related to the sale of inventory materials previously impaired (2024: Other impairment expenses of $0.4 million). During the six months ended June 30, 2025, the Company recognized other impairment expenses of $0.4 million, mainly related to obsolete inventory materials (2024: $1.4 million).

Expense (recovery) of asset retirement obligations

During the three and six months ended June 30, 2025, the Company recognized an asset retirement obligations expense of $0.2 million and $0.5 million, respectively. During the three and six months ended June 30, 2024, the Company recognized an asset retirement obligations expense of $45 thousand and recovery of asset retirement obligations of $1.0 million.

Other Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	2025	2024	2025	2024
General and administrative	14,279	12,928	27,850	26,484
Special projects and other costs	4,389	1,853	8,317	3,933
Share-based compensation	1,624	754	2,486	1,040
Restructuring, severance, and other costs	9,526	1,052	10,527	2,855

General and Administrative (“G&A”)

For the three and six months ended June 30, 2025, G&A expenses increased by 10% and 5%, respectively, compared to the same periods of 2024, mainly due to Colombian temporary taxes of $1.9 million and $2.9 million for the three and six months ended June 30, 2025, respectively.

Special projects and other costs

For the three and six months ended June 30, 2025, special projects and other costs increased by 137% and 111%, respectively, compared with the same periods of 2024, mainly due to SAARA's operating costs under the agreement with Ecopetrol, which was signed in June 2024.

Share-Based Compensation

For the three and six months ended June 30, 2025, share-based compensation increased by $0.9 million and $1.4 million, respectively, compared to the same periods of 2024. The increase was primarily 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 and six months ended June 30, 2025, restructuring, severance and other costs increased by $8.5 million and $7.7 million, respectively, compared to the same periods of 2024, mainly due to employee incentive payments, fees and expenses resulting from the recapitalization of the Company's interest in the ODL pipeline.

Non-Operating Costs

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Finance income	2,073	1,816	3,556	3,408
Finance expenses	(18,310)	(17,429)	(33,715)	(34,699)
Foreign exchange loss	(2,553)	(7,518)	(314)	(8,615)
Other income (loss)	1,303	(2,774)	1,191	(3,133)

Finance Income

For the three and six months ended June 30, 2025, finance income increased by $0.3 million and $0.1 million, respectively, compared with the same periods of 2024, mainly due to changes in interest rates on investment trust accounts related to abandonment requirements and average of cash balances during the period.

Finance Expenses

For three months ended June 30, 2025, finance expenses increased by $0.9 million, compared with the same period of 2024, mainly due to additional interest resulting from the FPI Recapitalization Loan (as defined below). For the six months ended June 30, 2025 finance expenses decreased by $1.0 million, compared with the same period of 2024, mainly due to lower other bank charges, partially offset by additional interest resulting from the FPI Recapitalization Loan.

Foreign Exchange Loss

For the three and six months ended June 30, 2025, the Company recognized foreign exchange losses of $2.6 million and $0.3 million, respectively, compared to losses of $7.5 million and $8.6 million for the same periods of 2024. The lower foreign exchange losses were primarily due to the appreciation of the COP against the USD during the first half of 2025, compared to a depreciation of the COP against the USD during the first half of 2024. These exchange rate movements impacted the Company's net working capital balances denominated in COP. Foreign exchange rates (COP:USD) as at June 30, 2025, and June 30, 2024, were 4,069.67:1 and 4,148.04:1, respectively.

Other Income (Loss)

For the three and six months ended June 30, 2025, the Company recognized other income of $1.3 million and $1.2 million, respectively, mainly from the sale of inventory and other assets from relinquished blocks, partially offset by other losses related to the recognition of contingencies. During the same periods of 2024, the Company recognized other loss of $2.8 million and $3.1 million, respectively, mainly attributable to contingencies, partially offset by income related to insurance compensation for the Sabanero block.

Gain (Loss) on Risk Management Contracts

($M)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Gain (loss) on oil price risk management contracts [1]	431	(3,796)	(3,710)	(7,285)
Realized gain on foreign exchange risk hedge [2]	43	3,832	43	6,447
Realized gain (loss) on risk management contracts	474	36	(3,667)	(838)
Unrealized gain (loss) on risk management contracts	3,556	(3,646)	8,342	(11,585)
Total gain (loss) on risk management contracts	4,030	(3,610)	4,675	(12,423)

[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 15 for further details.
[2] For determination of operating netback, during the three and six months ended June 30, 2025, the Company estimates an attribution of $Nil and $Nil, respectively, of the total realized FX hedge to production cost (excluding energy cost) (2024: $2.2 million and $3.5 million respectively), estimates an attribution of $Nil and $Nil, respectively, of the total realized FX hedge to energy (2024: $0.8 million and $1.4 million, respectively), and estimates an attribution of $Nil and $Nil, respectively, of the total realized FX hedge to transportation (2024: $0.6 million and $1.0 million), respectively. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.

For the three and six months ended June 30, 2025, the realized gain of $0.5 million and loss of $3.7 million, respectively, on risk management contracts was mainly due to a gain of $0.4 million and loss of $3.7 million, respectively, net of the positive cash settlement of $4.1 million and $4.1 million, respectively, from oil price contracts during the periods, partially offset by the put premiums paid for expired positions of $3.7 million and $7.8 million, respectively. In the same periods of 2024, the realized gain on risk management contracts was $36 thousand and a loss of $0.8 million, respectively, resulting from $3.8 million and $7.3 million, respectively, in premiums paid on oil price risk management contracts, partially offset by a gain of $3.8 million and $6.4 million, respectively, on the cash settlement of risk management contracts of foreign exchange currency.

For the three and six months ended June 30, 2025, risk management contracts had an unrealized gain of $3.6 million and $8.3 million, respectively, compared with a loss of $3.6 million and $11.6 million, respectively, in the same period 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.

Type of Instrument	Term	Benchmark	Volume (bbl)	Avg. Strike Prices Put $/bbl	Carrying Amount Assets	Carrying Amount Liabilities
Put Spread	October 2025 to December 2025	Brent	1,370,000	65/55	631	—
Put Spread	July 2025 to September 2025	Brent	1,461,000	70/55	434	—
Total as at June 30, 2025			2,831,000		1,065	—

Subsequently of the end of the quarter, the Company has not entered into 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 June 30, 2025, the Company has the following foreign currency derivatives contracts:

Type of Instrument	Term	Benchmark	Notional Amount/ Volume in USD	Avg. Put/Call Par forward (COP$)	Carrying Amount Assets	Carrying Amount Liabilities
Zero-cost collars	July 2025 to September 2025	USD/COP	60,000,000	4,200/4,795	1,777	—
Zero-cost collars	October 2025 to December 2025	USD/COP	30,000,000	4,250/4,787	1,284	—
Forward [1]	August 2025	USD/COP	10,423,124	4,206	—	223
Forward [1]	October 2025	USD/COP	7,741,875	4,247	—	168
Forward [1]	December 2025	USD/COP	7,666,063	4,289	—	180
Total as at June 30, 2025			115,831,062		3,061	571

(1) Contracts related to the FPI Recapitalization Loan (as defined below).

Following the end of the quarter, the Company entered into new hedges as follows:

Type of Instrument	Term	Benchmark	Notional Amount / Volume in USD	Avg. Strike Prices Par forward (COP$)
Forward [1]	December 2025	USD / COP	4,782,793	4,182
		Total	4,782,793	

(1) Contracts related to the FPI Recapitalization Loan (as defined below).

Income Tax Expense

($M)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Current income tax expense	(1,391)	(1,273)	(7,186)	(6,283)
Deferred income tax recovery (expense)	14,348	(31,386)	29,794	(52,961)
Total income tax recovery (expense)	12,957	(32,659)	22,608	(59,244)

For the three and six months ended June 30, 2025, the Company recognized a current income tax expense of $1.4 million and $7.2 million, respectively, compared to a current income tax expense of $1.3 million and $6.3 million, respectively, in the same period of 2024. Additionally, the Company recognized a deferred income tax recovery of $14.3 million and $29.8 million, compared with a deferred income tax expense of $31.4 million and $53.0 million, respectively, in the same period of 2024. The variance in the deferred tax was mainly due to foreign exchange rate fluctuations.

Net Loss

($M)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Net loss [1]	(455,212)	(2,846)	(427,688)	(11,349)
Per share – basic ($)	(5.89)	(0.03)	(5.50)	(0.13)
Per share – diluted ($)	(5.89)	(0.03)	(5.50)	(0.13)

(1) Refers to Net (loss) income, attributable to equity holders of the Company.

During the second quarter of 2025, the Company reported a net loss, attributable to equity holders of the Company, of $455.2 million, mainly resulting from a loss from operations of $474.8 million (net of a non-cash impairment expenses of $477.0 million), finance expenses of $18.3 million and foreign exchange expense of $2.6 million, partially offset by $14.1 million from share of income from associates, an income tax recovery of $13.0 million (including $14.3 million of deferred income tax recovery), $11.7 million of gain on the repurchase of the 2028 Senior Unsecured Notes (as defined below) net of the consent solicitation, and $4.0 million related to gain on risk management contracts. This compares with a net loss, attributable to equity holders of the Company, of $2.8 million, mainly resulting from an income tax expense of $32.7 million (including $31.4 million of deferred income tax expenses), finance expenses of $17.4 million, foreign exchange losses of $7.5 million and $3.6 million related to a loss on risk management contracts, partially offset by an income from operations of $45.2 million and $13.4 million from share of income from associates.

For the six months ended June 30, 2025, the Company reported a net loss, attributable to equity holders of the Company, of $427.7 million, mainly resulting from a loss from operations of $461.2 million (net of a non-cash impairment expense of $478.1 million) and finance expenses of $33.7 million, partially offset by $29.2 million from share of income from associates, an income tax recovery of $22.6 million (including $29.8 million of deferred income tax recovery), $11.9 million of gain on the repurchase of the 2028 Senior Unsecured Notes net of the consent solicitation, and $4.7 million related to gain on risk management contracts. This compared to a net loss, attributable to equity holders of the Company, of $11.3 million, mainly resulting from income tax expense of $59.2 million (including $53.0 million of deferred income tax expenses), finance expenses of $34.7 million, $12.4 million related to loss on risk management contracts and $8.6 million of foreign exchange losses, partially offset by income from operations of $74.9 million, and $27.3 million from share of income from associates.

Capital Expenditures and Acquisitions

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Development drilling	35,400	37,868	60,930	72,906
Development facilities	16,603	25,566	23,782	45,244
Colombia and Ecuador exploration	2,212	11,173	12,233	13,410
Other	264	1,521	1,198	7,855
Total Colombia and Ecuador upstream capital expenditures	**54,479**	**76,128**	**98,143**	**139,415**
Colombia infrastructure	4,834	3,467	7,534	8,023
Guyana exploration	89	603	436	2,141
Total capital expenditures [1]	**59,402**	**80,198**	**106,113**	**149,579**

[1] Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 for further details.

Capital expenditures for the three and six months ended June 30, 2025, were $59.4 million and $106.1 million respectively, compared with $80.2 million and $149.6 million respectively, in the same periods of 2024, as follows:

Development drilling. During the three and six months ended June 30, 2025, development drilling expenditures were $35.4 million and $60.9 million, respectively, compared with $37.9 million and $72.9 million respectively, for the same periods of 2024. During the second quarter of 2025, 26 development wells were drilled mainly in the Quifa and CPE-6 blocks in Colombia. In the same period of 2024, 28 development wells were drilled in the Quifa and CPE-6 blocks in Colombia, and 2 development wells were drilled in the Perico block in Ecuador. During the six months ended June 30, 2025, 39 development wells were drilled mainly in the Quifa and CPE-6 blocks, in Colombia, while in the same period of 2024 a total of 48 development wells were drilled in the Quifa and CPE-6 blocks in Colombia, and 3 development wells were drilled in the Perico block in Ecuador.

Development facilities. During the three and six months ended June 30, 2025, development facility expenditures were $16.6 million and $23.8 million, respectively, primarily related to the facility expansion and the installation of new and improved flow lines in the Cajua field, in the Quifa block, to support new well production and the SAARA connection. Additionally, the expansion of crude oil storage capacity in the CPE-6 block. For the same periods of 2024, development facility expenditures were $25.6 million and $45.2 million, respectively, mainly related to the increase of water-handling capacity at the CPE-6 block, the expansion of gas compression facilities production capacity in the VIM-1 block, injector well facilities in the Quifa block, the expansion of the Sabanero block facilities, and the purchase of facilities related to surface equipment in the Perico block.

Colombia and Ecuador Exploration. During the three and six months ended June 30, 2025, expenditures related to exploration activities were $2.2 million and $12.2 million, respectively, compared with $11.2 million and $13.4 million, respectively, in the same periods of 2024. During the three months ended June 30, 2025, the predrilling activities were ongoing for the drilling of one new exploratory well, and pre-seismic activities were ongoing for one 3D seismic acquisition project in Colombia. Details regarding exploration activities in Colombia and Ecuador are as follows:

Colombia. During the second quarter of 2025, the Company's exploration focus remained on the Lower Magdalena Valley and Llanos Basins in Colombia. At VIM-1, following engagement efforts with authorities and communities, the joint venture operating the VIM-1 block (Frontera 50% W.I., non-operator) has shifted its focus from Hidra-1 to the Guapo-1 exploratory well. By the second quarter 2025, all necessary designs and permits were secured for roadwork and site preparation for Guapo-1, with drilling and completion expected to occur in the second half of 2025. At the Llanos 119 block, the ANH's answer related to the exploration commitment transfer request to the VIM-46 block to acquire a 3D seismic survey is pending. In addition, the Company is also engaged in pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-99 and VIM-46 blocks.

Ecuador. At the Espejo block (Frontera holds a 50% W.I. and is a non-operator), the Espejo Sur-B3 well continued its long-term tests with a production of 330 bbl/d gross and a BSW of 78%.

Other. Other capital expenditures for the three and six months ended June 30, 2025, were $0.3 million and $1.2 million, respectively. These expenditures were primarily related to the implementation of new field production technologies at the CPE-6 block. The expenditures for the periods of 2024, were mainly related to generation facilities funded primarily through the reimbursement of insurance claim related to the Sabanero block.

Colombia infrastructure. Capital expenditures for the three and six months ended June 30, 2025, were $4.8 million and $7.5 million, respectively, compared with $3.5 million and $8.0 million, respectively, for the same periods of 2024. During the second quarter of 2025, investments totaling $3.9 million were made in Puerto Bahia, including: (i) $3.4 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 cargo terminal facilities. In addition, the second quarter also includes investment in the SAARA project. During the same periods of 2024, capital expenditures included investments in the SAARA project and Puerto Bahia.

Guyana exploration. During the three and six months ended June 30, 2025, Guyana exploration expenditures were $0.1 million and $0.4 million, respectively, compared to $0.6 million and $2.1 million, respectively during the same periods of 2024. These expenditures were associated with other capitalized costs.

Selected Quarterly Information

		2025		2024				2023	
Operational and financial results		**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Heavy crude oil production	(bbl/d)	27,535	27,167	27,740	25,312	24,839	23,398	23,002	24,097
Light and medium crude oil combined production	(bbl/d)	11,127	10,998	12,234	12,794	12,583	12,580	13,795	13,964
Total crude oil production	(bbl/d)	38,662	38,165	39,974	38,106	37,422	35,978	36,797	38,061
Conventional natural gas production	(mcf/d)	3,118	2,274	2,633	3,192	4,019	3,283	4,760	5,250
Natural gas liquids production	(boe/d)	1,846	1,913	1,970	1,950	1,785	1,639	1,635	1,820
Total production	(boe/d)	41,055	40,477	42,406	40,616	39,912	38,193	39,267	40,802
Sales volumes, net of purchases	(boe/d)	31,568	34,044	36,773	34,192	31,523	30,185	34,449	35,289
Brent price reference	($/bbl)	66.71	74.98	74.01	78.71	85.03	81.76	82.85	85.92
Oil and gas sales, net of purchases [1][2]	($/boe)	59.51	64.61	63.76	67.68	75.69	73.09	75.25	78.01
Gain (loss) on oil price risk management contracts [3][4]	($/boe)	0.15	(1.35)	0.07	(0.45)	(1.32)	(1.27)	(0.69)	(0.59)
Royalties [3]	($/boe)	(0.80)	(1.00)	(0.88)	(0.91)	(2.01)	(1.64)	(1.79)	(3.76)
Net sales realized price [1][2]	($/boe)	58.86	62.26	62.95	66.32	72.36	70.18	72.77	73.66
Production costs (excluding energy costs), net of realized FX hedge impact [2][3]	($/boe)	(9.01)	(10.04)	(7.66)	(8.88)	(10.79)	(10.21)	(9.69)	(8.82)
Energy costs, net of realized FX hedge impact [3]	($/boe)	(4.71)	(5.38)	(5.29)	(5.11)	(4.74)	(5.29)	(5.06)	(5.04)
Transportation costs, net of realized FX hedge impact [2][3]	($/boe)	(11.62)	(12.32)	(11.35)	(12.31)	(11.07)	(11.47)	(11.06)	(11.90)
Operating netback per boe [1][2]	($/boe)	33.52	34.52	38.65	40.02	45.76	43.21	46.96	47.90
Revenue	($M)	239,887	275,061	290,614	278,475	279,523	265,175	299,501	308,867
Net (loss) income [5]	($M)	(455,212)	27,524	(29,401)	16,588	(2,846)	(8,503)	92,038	32,582
Per share – basic ($)	($)	(5.89)	0.35	(0.36)	0.20	(0.03)	(0.10)	1.08	0.38
Per share – diluted ($)	($)	(5.89)	0.34	(0.36)	0.19	(0.03)	(0.10)	1.04	0.37
General and administrative	($M)	14,279	13,571	13,170	12,719	12,928	13,556	16,891	11,925
Operating EBITDA [6]	($M)	76,073	83,458	113,479	103,184	110,321	97,248	121,036	137,800
Capital expenditures [6]	($M)	59,402	46,711	85,866	82,411	80,198	69,381	82,292	74,130

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 for further details.
(2) 2024 and 2023 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 24 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 15 for further details.
(5) Refers to net (loss) income attributable to equity holders of the Company.
(6) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 24 for further details.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, movements in Brent oil benchmark prices, the timing of cargo shipments, and fluctuations in crude oil price differentials. During 2024 and 2025, production 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; and (ii) increased natural gas liquids production resulting from facility development in the VIM-1 block. These increases were partially offset by a decrease in light and medium crude oil combined production and conventional natural gas production mainly due to natural decline. Transportation costs 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. Energy costs fluctuated in line with market prices. In addition, production costs (excluding energy costs) have also fluctuated, mainly due to inflationary pressures on services, wage indexation, well services and maintenance activities, and changes in barrels produced affecting variable costs.

Trends in the Company's net (loss) income, 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 oil and gas and exploration and evaluation assets, DD&A, foreign exchange gains or losses, and gains or losses from risk management contracts, which fluctuate mainly with changes in hedging strategies and crude oil benchmark forward prices. 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.

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**").

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 (formerly PIL) (which holds a 35% interest in the ODL Pipeline)	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 20,000-27,000 tons per year of fresh fruit bunches	100% interest in 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

		Q2 2025	Q1 2025	Q2 2024	Six months ended June 30 2025	Six months ended June 30 2024
Operational and IFRS Results						
Volumes pumped at oil pipeline facility	(bbl/d)	235,804	236,387	249,196	236,094	247,619
Volume throughput at port liquids facility	(bbl/d)	53,280	51,579	61,798	52,434	57,579
Volumes handled at RORO port general cargo facility	(Units)	28,283	18,223	18,986	46,506	31,835
Break Bulk Volumes at port	(Tons/m3)	7,538	41,198	11,256	48,736	19,737
Volumes of water received in SAARA from production fields	(bwpd)	119,409	81,481	14,467	100,550	23,870
Production of fresh fruit bunches	(Tons)	7,039	7,684	8,895	14,723	13,990
Infrastructure Colombia segment income	($M)	14,278	15,296	14,620	29,574	27,172
Infrastructure Colombia segment cash flow from operating activities	($M)	1,594	25,580	29,922	27,174	30,565
Non IFRS Results [(1)]						
Adjusted Infrastructure Revenues	($M)	44,969	44,912	43,055	89,881	83,962
Adjusted Infrastructure EBITDA	($M)	27,057	28,603	27,823	55,660	53,510
Adjusted Infrastructure Cash	($M)	43,346	57,795	48,831	43,346	48,831
Adjusted Infrastructure Debt	($M)	224,262	117,935	113,763	224,262	113,763
Capital Expenditures Infrastructure Colombia Segment	($M)	4,834	2,700	3,467	7,534	8,023

(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 24 for further details.

Infrastructure Colombia Segment Results

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

($M)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Revenue	14,479	12,894	27,343	23,422
Costs	(10,493)	(7,598)	(19,423)	(15,747)
General and administrative expenses	(1,180)	(1,389)	(2,687)	(2,868)
Depletion, depreciation and amortization	(2,100)	(1,962)	(4,126)	(3,778)
Other operating costs	(552)	(732)	(766)	(1,158)
Infrastructure Colombia income (loss) from operations	**154**	**1,213**	**341**	**(129)**
Share of income from associates - ODL	14,124	13,407	29,233	27,301
Infrastructure Colombia segment income	**14,278**	**14,620**	**29,574**	**27,172**
Infrastructure Colombia segment cash flow from operating activities	1,594	29,922	27,174	30,567
Capital Expenditures Infrastructure Colombia Segment [(1)]	4,834	3,467	7,534	8,023

(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 24 for further details.

The Company's Infrastructure Colombia Segment income for the three months ended June 30, 2025, decreased by 2%, compared with the same period of 2024. For the first half of 2025, the Company's Infrastructure Colombia Segment increased $2.4 million, compared to the same period of 2024, mainly due to a higher share of income from ODL, primarily driven by higher revenues resulting from a 7.8% increase in pipeline transportation tariffs implemented in September 2024 and operational cost efficiencies at Puerto Bahia's port, partially offset by higher operating costs in SAARA.

Segment capital expenditures for the three and six months ended June 30, 2025, were $4.8 million and $7.5 million, respectively, compared with $3.5 million and $8.0 million, respectively, for the same periods of 2024. During the second quarter of 2025, investments totaling $3.9 million were made in Puerto Bahia, including: (i) $3.4 million towards the connection project between Puerto Bahia's port facility and the Cartagena refinery, (ii) tank maintenance, and (iii) general cargo terminal facilities. The second quarter also includes investment in the SAARA project. During the same periods of 2024, capital expenditures included SAARA project and Puerto Bahia investments.

ODL Pipeline

The Company, through its 100%-owned subsidiary FPI (formerly PIL), 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 and six months ended June 30, 2025, ODL generated an EBITDA of $69.3 million and $144.1 million, respectively, and net income of $40.4 million and $83.5 million, respectively. The ODL results are consolidated through the equity method in the Interim 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 June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Revenue	87,114	86,174	178,680	172,971
FEC revenue (billed units)	7,499	7,522	14,754	14,974
Third party revenues	79,615	78,652	163,926	157,997
Costs	(12,955)	(12,572)	(24,914)	(23,968)
General administrative expenses	(4,872)	(5,270)	(9,690)	(9,851)
Depletion, depreciation and amortization	(7,586)	(7,933)	(14,048)	(15,859)
Other non-operating expense	(217)	(1,465)	(2,127)	(3,287)
Income tax	(21,128)	(20,627)	(44,377)	(42,002)
ODL Net Income	**40,356**	**38,307**	**83,524**	**78,004**

($M)	**June 30 2025**	**December 31 2024**
ODL debt	38,330	36,954
ODL cash and cash equivalents	33,743	76,979

The following table shows the volumes pumped per injection point:

	Three months ended June 30		Six months ended June 30	
(bbl/d)	**2025**	**2024**	**2025**	**2024**
At Rubiales Station	133,187	172,163	152,978	169,770
At Jagüey, Palmeras and Caño Sur Stations	102,617	77,033	83,116	77,849
Total	**235,804**	**249,196**	**236,094**	**247,619**

The following table shows the volumes received per block:

	Three months ended June 30		Six months ended June 30	
(bbl/d)	**2025**	**2024**	**2025**	**2024**
Rubiales	93,129	102,512	97,118	101,865
Quifa	29,630	29,460	29,245	29,151
CPE-6 and Sabanero	968	3,118	974	3,316
Other blocks	56,186	100,048	72,470	98,863
Total	**179,913**	**235,138**	**199,807**	**233,195**

For the three and six months ended June 30, 2025, the Company recognized $14.1 million and $29.2 million, respectively, as its share of income from ODL, which was higher than the same periods of 2024 by $0.7 million and $1.9 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 received and pumped.

During the three and six months ended June 30, 2025, ODL declared net dividends to FPI of $Nil and $52.9 million, respectively (2024: $Nil and $54.9 million respectively), and a return of capital of $Nil and $Nil, respectively (2024: $Nil and $7.9 million, respectively). During the three and six months ended June 30, 2025, FPI received cash of $Nil and $26.2 million, respectively, in dividends from ODL (2024: $27.4 million and $27.4 million, respectively in dividends and return of capital from ODL). The remaining declared amount is expected to be received during the second half of 2025. Subsequently, in July 14, 2025, ODL declared dividends of $4.4 million to FPI, payable in a single installment in December 2025.

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) and break bulk services in the general cargo terminal.

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Revenue	11,164	11,243	21,031	20,948
Liquids port facility	6,834	8,020	13,168	15,122
FEC liquids port facility	1,360	1,868	2,151	4,020
Third party liquids port facility	5,474	6,152	11,017	11,102
General cargo	4,330	3,223	7,863	5,826
Costs	(6,103)	(5,604)	(11,105)	(11,673)
General and administrative expenses	(1,065)	(1,270)	(2,411)	(2,674)
Depletion, depreciation and amortization	(1,711)	(1,754)	(3,426)	(3,404)
Other operating costs	(552)	(732)	(766)	(1,158)
Puerto Bahia Operating Income	1,733	1,883	3,323	2,039

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

	Three months ended June 30		Six months ended June 30	
(bbl/d)	**2025**	**2024**	**2025**	**2024**
FEC volumes	10,914	13,353	9,658	15,000
Third party volumes	42,366	48,445	42,776	42,579
Total	**53,280**	**61,798**	**52,434**	**57,579**

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

		Three months ended June 30		Six months ended June 30	
		2025	**2024**	**2025**	**2024**
RORO	Units [1]	28,283	18,986	46,506	31,835
RORO	Dwell time in days [2]	24	70	32	87
Containers	TEUs [3]	3,993	146	5,249	306
Break Bulk Volumes	Tons/m^3 [4]	7,538	11,256	48,736	19,737

(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 and six months ended June 30, 2025, Puerto Bahia had an operating income of $1.7 million and $3.3 million, respectively (2024: $1.9 million and $2.0 million, respectively). For the three and six months ended June 30, 2025, Puerto Bahia's general cargo revenues increased by 34% and 35%, respectively, mainly due to higher volumes handled, particularly livestock during the first quarter, as well as growing container activity throughout 2025. In contrast, revenues from the liquids terminal declined compared with the same periods in 2024, mainly due to lower volumes of Nafta resulting from lower requirements from third parties.

The Reficar connection's construction was completed by the end of the quarter and, the Company's efforts shift to the first transported volumes, which are expected during the third quarter of 2025. Ongoing strategic investments in the port, including the LPG joint venture with Empresas Gasco, are progressing as planned.

Water Treatment Facility and Palm Oil Plantation

In 2021, Frontera launched a feasibility analysis of the agricultural water reuse system SAARA, which consist 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 2,900 hectares currently planted, its oil palm plantation yielded 26,089 tons of fresh fruit bunches in the last 12 months. These crops have an estimated productive lifespan of 30 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 six months ended June 30, 2025, SAARA processed approximately 18 million barrels of water, that irrigated approximately 800 hectares of palm oil crops in ProAgrollanos.

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

	Three months ended June 30		Six months ended June 30	
($M)	**2025**	**2024**	**2025**	**2024**
Revenue	3,315	1,651	6,312	2,474
Fresh fruit bunches for palm oil	1,425	1,451	3,118	2,274
SAARA	1,890	200	3,194	200
Costs	(4,390)	(1,994)	(8,318)	(4,074)
Fresh fruit bunches for palm oil	(1,258)	(1,050)	(2,357)	(1,759)
SAARA	(3,132)	(944)	(5,961)	(2,315)
General and administrative expenses	(115)	(119)	(276)	(194)
Depletion, depreciation and amortization	(389)	(208)	(700)	(374)
SAARA and palm oil plantation operating loss	**(1,579)**	**(670)**	**(2,982)**	**(2,168)**

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

		Three months ended June 30		Six months ended June 30	
($M)		**2025**	**2024**	**2025**	**2024**
Fresh fruit bunches for palm oil (produced - sold)	(Tons)	7,039	8,895	14,723	13,990
Production per hectare per year [1]	(Tons/ha/year)	8.86	7.42	8.86	7.42
Palm oil fruit price	($/Ton)	189	166	200	164
Volumes of reverse osmosis water treated	(bwpd)	119,409	14,467	100,550	23,870
Volumes of water irrigated for palm oil cultivation [2]	(bwpd)	118,831	14,398	100,323	19,006

(1) Tons per hectare per year for the three months ended June 30, are calculated using the total production for the last 12 months ended June 30.
(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 ended June 30, 2025, sales from fresh fruit bunches of oil palm totaled $1.4 million. Sales were consistent with the same quarter in 2024, despite a decline in fresh fruit bunches available for palm oil production, which was partially offset by higher market prices. For the six months ended June 30, 2025, sales from fresh fruit bunches of oil palm totaled $3.1 million, an increase of $0.8 million compared with the same period of 2024, primarily driven by higher market prices and increased production. 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 and six months ended June 30, 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 June 30, 2025, the project processed 119,409 barrels of water per day, generating revenue of $1.9 million, an increase of 47% compared with the previous quarter. The Company remains focused on reaching its goal of processing 250,000 bwpd.

Agro Cascada, a wholly owned subsidiary of the Company, borrowed COP$41,927 million (approximately $9.5 million) from Citibank Colombia under a one-year facility pursuant to the Agro Cascada Working Capital Loan (as defined below) to support development of the Company's water treatment facilities. Please refers to Liquidity and Capital Resources section on page 31.

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

EBITDA is a commonly used non-IFRS financial measure that adjusts net (loss) income as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA 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, as they are not indicative of the underlying core operating performance of the Company.

The following table provides a reconciliation of net (loss) income to Operating EBITDA:

($M)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Net loss [1]	(455,212)	(2,846)	(427,688)	(11,349)
Finance income	(2,073)	(1,816)	(3,556)	(3,408)
Finance expenses	18,310	17,429	33,715	34,699
Income tax (recovery) expense	(12,957)	32,659	(22,608)	59,244
Depletion, depreciation and amortization	60,600	63,188	127,994	129,000
Colombian temporary taxes [2]	1,919	—	2,858	—
Expense (recovery) of asset retirement obligation	151	45	526	(997)
Impairment expense	476,960	392	478,094	1,419
Trunkline costs[3]	—	—	2,000	—
Post-termination obligation	(406)	(364)	(109)	186
Share-based compensation	1,624	754	2,486	1,040
Restructuring, severance and other costs	9,526	1,052	10,527	2,855
Share of income from associates	(14,124)	(13,407)	(29,233)	(27,301)
Foreign exchange loss	2,553	7,518	314	8,615
Other (income) loss	(1,303)	2,774	(1,191)	3,133
Unrealized (gain) loss on risk management contracts	(3,556)	3,646	(8,342)	11,585
Non-controlling interests	(168)	(288)	(295)	(443)
Debt extinguishment cost	5,964	—	5,964	—
Gain on repurchase of notes	(11,735)	(415)	(11,925)	(709)
Operating EBITDA	**76,073**	**110,321**	**159,531**	**207,569**

(1) Refers to net (loss) income 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.
(3) Other cost related to external road maintenance expenses associated with damage caused by the heavy rainy season of $0.5 million and $0.5 million, for the three and six months ended June 30, 2025, respectively, were not included.

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 June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Consolidated Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	60,487	87,033	103,069	149,882
Additions to exploration and evaluation assets	1,692	10,467	3,527	12,954
Total additions in Consolidated Statements of Cash Flows	**62,179**	**97,500**	**106,596**	**162,836**
Non-cash adjustments [1]	(2,768)	(17,302)	(440)	(13,257)
Cash adjustments	(9)	—	(43)	—
Total Capital Expenditures	**59,402**	**80,198**	**106,113**	**149,579**
Capital Expenditures attributable to Infrastructure Colombia Segment	4,834	3,467	7,534	8,023
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	54,568	76,731	98,579	141,556
Total Capital Expenditure	**59,402**	**80,198**	**106,113**	**149,579**

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

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 June 30		Six months ended June 30	
($M) [1]	**2025**	**2024**	**2025**	**2024**
Revenue Infrastructure Colombia Segment	14,479	12,894	27,343	23,422
Revenue from ODL	87,114	86,174	178,680	172,971
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	30,490	30,161	62,538	60,540
Adjusted Infrastructure Revenues	**44,969**	**43,055**	**89,881**	**83,962**
Operating cost Infrastructure Colombia Segment	(10,493)	(7,598)	(19,423)	(15,747)
Operating Cost from ODL	(12,955)	(12,572)	(24,914)	(23,968)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	(4,534)	(4,400)	(8,720)	(8,389)
Adjusted Infrastructure Operating Costs	**(15,027)**	**(11,998)**	**(28,143)**	**(24,136)**
General and administrative Infrastructure Colombia Segment	(1,180)	(1,389)	(2,687)	(2,868)
General and administrative from ODL	(4,872)	(5,270)	(9,690)	(9,851)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	(1,705)	(1,845)	(3,392)	(3,448)
Adjusted Infrastructure General and Administrative	**(2,885)**	**(3,234)**	**(6,079)**	**(6,316)**

[1] Revenues and expenses related to ODL are accounted for using the equity method, as described in Note 12 of the Interim 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]	June 30 2025	December 31 2024
Cash and cash equivalents - unrestricted	184,860	192,577
Cash and cash equivalents of Non-Infrastructure Colombia Segment's	(153,324)	(147,097)
Total Cash Infrastructure Colombia Segment	31,536	45,480
Cash and cash equivalent from ODL	33,743	76,979
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	11,810	26,943
Adjusted Infrastructure Cash	**43,346**	**72,423**
Short-Term and Long-Term Debt	521,099	493,764
Debt of Non-Infrastructure Colombia Segment's	(310,253)	(389,803)
Total Loans	210,846	103,961
Debt from ODL	38,330	36,954
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	13,416	12,934
Adjusted Infrastructure Debt	**224,262**	**116,895**

[1] 35% ODL participation is accounted using the equity method in the Interim 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 June 30		Six months ended June 30	
($M)	2025	2024	2025	2024
Adjusted Infrastructure Revenue	44,969	43,055	89,881	83,962
Adjusted Infrastructure Operating Costs	(15,027)	(11,998)	(28,143)	(24,136)
Adjusted Infrastructure General and Administrative	(2,885)	(3,234)	(6,078)	(6,316)
Adjusted Infrastructure EBITDA	**27,057**	**27,823**	**55,660**	**53,510**

Net Sales

Net sales 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 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 10.

Operating Netback

Operating netback is a non-IFRS financial measure and operating netback per boe is a non-IFRS ratio. Operating netback per boe is used to assess the net margin of the Company's production 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" section on page 9.

Oil and Gas Sales, Net of Purchases

Oil and gas sales, 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 per boe and Oil and gas sales, 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 June 30		Six months ended June 30	
	2025	2024	2025	2024
Produced crude oil and products sales ($M) (1)	181,081	224,646	390,708	433,689
Purchased crude net margin ($M) (2)(3)	(10,138)	(7,516)	(21,790)	(15,785)
Oil and gas sales, net of purchases ($M) (2)	**170,943**	**217,130**	**368,918**	**417,904**
Sales volumes, net of purchases - (boe)	2,872,688	2,868,593	5,936,619	5,615,246
Produced crude oil and gas sales ($/boe)	63.04	78.31	65.81	77.23
Oil and gas sales, net of purchases ($/boe) (2)	59.51	75.69	62.14	74.42

(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 19 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 June 30		Six months ended June 30	
	2025	2024	2025	2024
Oil and gas sales, net of purchases ($M) (1)(2)	170,943	217,130	368,918	417,904
Crude oil sales volumes, net of purchases - (bbl)	2,826,599	2,804,205	5,859,395	5,498,687
Conventional natural gas sales volumes - (mcf)	262,629	366,869	440,385	665,013
Realized oil price, net of purchases ($/bbl) (2)	59.93	76.66	62.53	75.27
Realized conventional natural gas price ($/mcf)	5.93	5.88	5.80	6.05

(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 June 30		Six months ended June 30	
	2025	2024	2025	2024
Oil and gas sales, net of purchases ($M) (1)(2)	170,943	217,130	368,918	417,904
Gain (loss) on oil price risk management contracts, net ($M) (3)	431	(3,796)	(3,710)	(7,285)
(-) Royalties ($M)	(2,304)	(5,774)	(5,364)	(10,280)
Net sales ($M)	169,070	207,560	359,844	400,339
Sales volumes, net of purchases - (boe)	2,872,688	2,868,593	5,936,619	5,615,246
Oil and gas sales, net of purchases ($/boe) (2)	59.51	75.69	62.14	74.42
Premiums received (paid) on oil price risk management contracts (4)	0.15	(1.32)	(0.62)	(1.30)
Royalties ($/boe)	(0.80)	(2.01)	(0.90)	(1.83)
Net sales realized price ($/boe) (2)	**58.86**	**72.36**	**60.62**	**71.29**

(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 15 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 June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Purchased crude oil and products sales ($M)	49,139	49,035	106,502	100,320
(-) Cost of diluent and oil purchased ($M) (1)	(58,609)	(55,153)	(127,469)	(113,012)
Puerto Bahía inter-segment costs (2)	(668)	(1,398)	(823)	(3,093)
Purchased crude net margin ($M) (2)	**(10,138)**	**(7,516)**	**(21,790)**	**(15,785)**
Sales volumes, net of purchases - (boe)	2,872,688	2,868,593	5,936,619	5,615,246
Purchased crude net margin ($/boe) (2)	**(3.53)**	**(2.62)**	**(3.67)**	**(2.81)**

(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 June 30		Six months ended June 30	
	2025	**2024**	**2025**	**2024**
Production costs (excluding energy costs) ($M)	32,367	41,401	68,046	78,240
(-) Realized gain on FX hedge attributable to production costs (excluding energy costs) ($M) (1)	(43)	(2,203)	(43)	(3,540)
SAARA inter-segment costs	1,323	—	2,236	—
Production costs (excluding energy costs), net of realized FX hedge impact ($M) (2)	33,647	39,198	70,239	74,700
Production (boe)	3,736,005	3,631,992	7,378,646	7,107,646
Production costs (excluding energy costs), net of realized FX hedge impact ($/boe)	9.01	10.79	9.52	10.51

(1) See “Gain (Loss) on Risk Management Contracts” on page 15 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 June 30		Six months ended June 30	
	2025	2024	2025	2024
Energy costs ($M)	17,591	17,997	37,175	36,965
(-) Realized gain on FX hedge attributable to energy costs ($M) (1)	—	(770)	—	(1,351)
Energy costs, net of realized FX hedge impact ($M) (2)	17,591	17,227	37,175	35,614
Production (boe)	3,736,005	3,631,992	7,378,646	7,107,646
Energy costs, net of realized FX hedge impact ($/boe)	4.71	4.74	5.04	5.01

(1) See "Gain (Loss) on Risk Management Contracts" on page 15 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 June 30		Six months ended June 30	
	2025	2024	2025	2024
Transportation costs ($M)	38,701	34,917	78,250	70,112
(-) Realized gain on FX hedge attributable to transportation costs ($M) (1)	—	(634)	—	(1,043)
Puerto Bahía inter-segment costs (2)	692	470	1,328	901
Transportation costs, net of realized FX hedge impact ($M) (2)(3)	39,393	34,753	79,578	69,970
Net production (boe)	3,389,204	3,139,955	6,652,293	6,210,568
Transportation costs, net of realized FX hedge impact ($/boe) (2)	11.62	11.07	11.96	11.27

(1) See "Gain (Loss) on Risk Management Contracts" on page 15 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.

4. LIQUIDITY AND CAPITAL RESOURCES

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

- capital expenditures for exploration, production, and development, 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 June 30, 2025, the Company had a total cash balance of $197.5 million (including $12.7 million in restricted cash), which was $25.3 million lower than at December 31, 2024.

For the six months ended June 30, 2025, the Company generated $111.9 million, of cash from operations, which was used to fund cash outflows of $108.7 million for capital expenditures and other investing activities. During the same period, financing activities generated net outflows of $14.4 million. These included $105.2 million in the full repayment of the PIL Loan Facility, $66.4 million in repurchases of the 2028 Unsecured Notes, $30.2 million used to repurchase Common Shares under the January 2025 SIB (as defined below), $18.4 million in other financing charges, $12.2 million toward principal payments on the FPI Recapitalization Loan and the Agro Cascada Working Capital Loan, $0.2 million in transaction costs of FPI Recapitalization Loan, $6.9 million in dividends paid to equity holders and $3.5 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. As a result, the Company's net working capital[(1)] improved by $50.0 million, reducing the deficit to $50.6 million as at June 30, 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 June 30, 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 June 30, 2025, the Company's restricted cash position was $12.7 million, representing a decrease of $17.6 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 38.

[(1)] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures'' section on page 24 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 $6.0 million held by the Company.

During the three and six months ended June 30, 2025, the Company repurchased $80.0 million and $81.0 million, respectively, in the aggregate amount of its 2028 Unsecured Notes pursuant to the Offer and Solicitation and in the open market for a cash consideration of $57.6 million and $58.4 million, respectively. As a result, during the three and six months ended June 30, 2025 the Company recognized a gain of $11.7 million and $11.9 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 June 30, 2025, was $310.3 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 June 30, 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 greater of $100.0 million and 10% 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 June 30, 2025, the Company was in compliance with all such covenants.

Pursuant to the requirements under the Indenture, the Company reported consolidated total indebtedness of $353,764,000 as at June 30, 2025, and, for the twelve months ended as of June 30, 2025, a consolidated adjusted EBITDA of $366,729,000 and a consolidated interest expense of $52,695,000.

(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 June 30 2025
Short-term and Long-term debt (1)	$	319,536
Total lease liabilities (2)		12,768
Customers prepayment (3)		25,586
Risk management liability net (4)		(4,126)
Consolidated Total Indebtedness		**353,764**
(-) Cash and Cash Equivalents (5)		(149,093)
(=) Net Debt	**$**	**204,671**

(1) Excludes $201.6 million of long-term debt attributable to the Unrestricted Subsidiaries.

(2) Excludes $1.5 million of lease liabilities attributable to the Unrestricted Subsidiaries.

(3) The customer prepayment balance amounts to $27.9 million. This line includes the customer prepayment relates to one cargo of crude oil to be delivered in the third quarter of 2025.

(4) Excludes $0.6 thousand of net risk management liability attributable to the Unrestricted Subsidiaries.

(5) Includes unrestricted cash and cash equivalents attributable to the guarantors as at June 30, 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 comprises various tranches, the last of which matures in December 2031, with principal payments made semi-annually. The FPI Recapitalization Loan comprises: 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 June 30, 2025, the carrying value of the FPI Loan Facility is $Nil (December 31, 2024: $94.5 million). As at June 30, 2025, the FPI Loan Facility debt service reserve account has a balance of $Nil. (December 31, 2024: $15.9 million). As at June 30, 2025, the carrying value of the FPI Recapitalization Loan is $201.6 million, which includes short-term debt of $33.7 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 prepaid $1.0 million of the Agro Cascada Working Capital Loan during the second quarter. As at June 30, 2025, the carrying value of the Agro Cascada Working Capital Loan was $9.3 million (December 31, 2024: $9.5 million). Subsequent to the end of the second quarter, the Company prepaid a further $0.5 million of the loan facility.

[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 June 30, 2025, the Company had issued letters of credit and guarantees for exploration and abandonment funds totaling $111.6 million (against total credit lines of $170.7 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 $6.3 million as at June 30, 2025, and has a maturity date of 72 months from April 3, 2024. The Solar Plant Debt bears interest equivalent to IBR plus 5.75%, payable monthly on the outstanding amount. As at June 30, 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 June 30, 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 June 30, 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 and contractual obligations as at June 30, 2025, undiscounted by calendar year, are presented below:

As at June 30, 2025 ($M)	2025	2026	2027	2028	2029	Subsequent to 2030	Total
Short-term and long-term debt principal and interest	57,844	65,598	63,444	362,380	38,065	119,215	706,546
Lease liabilities	3,670	5,117	2,721	2,605	1,979	1,241	17,333
Total financial obligations	**61,514**	**70,715**	**66,165**	**364,985**	**40,044**	**120,456**	**723,879**
Transportation							
Ocensa P-135 ship-or-pay agreement	15,350	—	—	—	—	—	15,350
ODL agreements	54	—	—	—	—	—	54
Other transportation and processing commitments	7,119	14,519	—	—	—	—	21,638
Exploration and evaluation							
Minimum work commitments (1)	12,396	10,171	—	5,066	—	—	27,633
Other commitments							
Operating purchases, community obligations and others	70,926	866	256	260	264	2,513	75,085
Energy supply commitments	21,432	14,986	9,489	4,454	1,070	2,224	53,655
Total Commitments	**127,277**	**40,542**	**9,745**	**9,780**	**1,334**	**4,737**	**193,415**

(1) The Company has been reducing the value of its exploratory commitments as they are executed. Some of these commitments are still pending accreditation by the ANH; however, the Company does not consider this situation to represent a risk.

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

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit became effective, and 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.

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 hold 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. The assignment of this 4.52% participating interest remains subject to the approval of the Government of Guyana, but is believed to be 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 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**") sent a notice of intent to the GoG, by which a 90-day period for consultations and negotiations initiated between the parties to resolve the dispute amicably ("**Notice of Intent**").

On July 23, 2025, the GoG, through its legal counsel, responded to the Investors, rejecting their claims regarding the Corentyne block license. The GoG reaffirmed its view that the Joint Venture's interest expired on June 28, 2024, but noted that it may consider a final meeting with the Investors, on a without prejudice basis, in October 2025, and the Joint Venture would be informed as to whether such a meeting will occur in September 2025.

The Joint Venture remains firmly of the view that its interests in, and the license for, the Corentyne block remain in place and in good standing and that the PA has not been terminated. Although the 90-day consultation and negotiation period derived from the Notice of Intent has now expired, the Joint Venture and its stakeholders continue to invite the GoG to amicably resolve the issues affecting the Joint Venture's investments in the Corentyne block. Should the parties not reach a mutually agreeable solution, the Joint Venture and its stakeholders are prepared to assert their legal rights.

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, and the Corentyne E&E asset's carrying value as of June 30, 2025 is $Nil (December 31, 2024, $431.9 million). See "Performance Highlights" above for additional detail.

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.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at August 12, 2025:

	Number
Common shares	69,983,214
DSUs (1)	1,230,969
RSUs (2)	2,224,182

(1) DSUs represent a future right to receive Common Shares (or the cash equivalent) 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, 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 directors 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, 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.

Purchases subject to the NCIBs 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. 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 August 12, 2025, the Company had repurchased for cancellation a total of 78,400 Common Shares under 2025 NCIB for approximately $0.4 million with an additional 3,424,562 Common Shares remaining available for repurchase under the 2025 NCIB.

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 November 6, 2024, the Company announced its intention to commence another SIB to purchase up to $30 million of its Common Shares for cancellation at a fixed price per share.

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, or $3.9 million in the aggregate. 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 six months ended June 30, 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

(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.

Pursuant to the Company's dividend policy, the Company's Board of Directors has declared a dividend of CAD$0.0625 per Common Share to be paid on or around October 16, 2025, to shareholders of record at the close of business on October 2, 2025.

6. RELATED-PARTY TRANSACTIONS

The following table provide the total balances outstanding, commitments, and transactional amounts with related parties as at June 30, 2025, and December 31, 2024, and for the three and six months ended June 30, 2025, and 2024, respectively:

		June 30, 2025, and December 31, 2024			Three months ended June 30	Six months ended June 30
($M)		Receivables from ODL Investment	Accounts Payable	Commitments	Purchases/Services	
ODL	2025	26,930	3,042	54	7,499	14,754
	2024	—	2,901	356	7,522	14,974

The related-party transactions correspond to dilution services for a total commitment of $0.1 million until 2025.

As at June 30, 2025, Loans includes $5.0 million balance (December 31, 2024, $Nil) 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) as part of the second lien of the FPI Recapitalization Loan.

7. 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.

See the "Liquidity and Capital Resources" section on page 31 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.

The Company will continue to consider investor-focused initiatives in 2025 and beyond, including potential additional dividends, distributions, share or bond buybacks, based on the overall results of the businesses, oil prices and cash flow generation. Additionally, the Company also continues to consider all options to enhance the value of its Common Shares, and in so doing may consider forms of strategic initiatives or transactions, which may include a further return of capital to shareholders, a merger or a business combination, or the transfer, sale or other disposition of all or a significant portion of the business, assets or securities of the Company or the recapitalization of interests in one or more subsidiaries or in assets of the Company, whether in one or a series of transactions. However, there can be no assurance that any such initiative or transaction will occur or if it occurs, the timing thereof.

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 2024 Annual Consolidated Financial Statements, copies of which are available on SEDAR+ at www.sedarplus.ca.

8. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Interim 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 2024 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 2024 Annual Consolidated Financial Statements, including management's evaluation of their impact and implementation progress.

The preparation of the Interim 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 Interim 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.

The effect of the global economy, including the impact of the U.S. trade tariffs affecting on numerous countries including Colombia, the Russia-Ukraine conflict, the Middle East conflict, and the associated volatility in oil prices, may negatively impact the Company. The uncertainty these events create has resulted in a challenging economic environment marked by more volatile commodity prices, foreign exchange rates, long-term interest rates, and changes in international trade policies. The outcome of the Middle East conflict remains uncertain and may have wide-ranging global economic consequences. Global oil prices have remained highly volatile since the conflict began, and there is a risk that it could lead to wider regional instability in the Middle East, which is home to some of the world's biggest oil producers. During the year, the U.S. government has enacted trade tariffs on numerous countries including Colombia and has more recently reached trade agreements with several countries which have agreed to the imposition of broad tariffs. The Company continues to monitor the situation for any new developments. The Company could be adversely affected by the imposition of new tariffs or adverse developments in the diplomatic and commercial relations between the United States and Colombia or the United States and other countries, which could 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.

To date, these events have not impacted the Company's ability to carry on business, and there have been no significant delays or direct security issues affecting the Company's operations, offices, or personnel. The long-term impacts of the conflicts remain uncertain, and the Company continues to monitor the evolving situation. This presents uncertainty and risk with respect to management's judgments, estimates, and assumptions used in the preparation of the Interim 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 2024 Annual Consolidated Financial Statements.

9. 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 April 1, 2025, and ending June 30, 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 June 30, 2025.

There has been no change in the Company's ICFR during the period beginning on April 1, 2025, and ending on June 30, 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 June 30, 2025.

10. FURTHER DISCLOSURES

Production Reporting by Block

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

		Production				
Producing blocks		**Q2 2025**	**Q1 2025**	**Q2 2024**	**2025**	**2024**
Quifa	(bbl/d)	17,576	16,766	17,371	17,173	17,115
CPE-6	(bbl/d)	7,771	8,056	6,947	7,913	6,588
Guatiquia	(bbl/d)	5,385	5,119	5,539	5,253	5,575
Sabanero	(bbl/d)	2,189	2,346	520	2,267	416
Vim1	(boe/d)	1,960	1,840	1,856	1,900	1,718
Perico	(bbl/d)	1,045	1,197	1,655	1,121	1,567
Cubiro	(bbl/d)	1,057	1,213	1,491	1,135	1,476
Cravoviejo	(bbl/d)	1,242	1,199	1,314	1,221	1,331
Other blocks	(boe/d)	2,830	2,741	3,219	2,783	3,267
Total production	**(boe/d)**	**41,055**	**40,477**	**39,912**	**40,766**	**39,053**

Production Reporting

Production volumes are reported on a Company's W.I. basis before royalties. In Ecuador, the government has a variable share of the total volumes produced under the Perico and Espejo joint venture exploration and extraction contracts. 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:

		Net Production				
					Six months ended June 30	
Producing blocks in Colombia		**Q2 2025**	**Q1 2025**	**Q2 2024**	**2025**	**2024**
Heavy crude oil	(bbl/d)	25,593	24,971	21,534	25,284	21,194
Light and medium crude oil combined	(bbl/d)	8,759	8,386	9,496	8,574	9,630
Conventional natural gas	(mcf/d)	3,118	2,269	4,019	2,696	3,648
Natural gas liquids	(boe/d)	1,395	1,453	1,651	1,424	1,581
Net production Colombia	**(boe/d)**	**36,294**	**35,208**	**33,386**	**35,755**	**33,045**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	950	1,047	1,119	998	1,079
Net production Ecuador	**(bbl/d)**	**950**	**1,047**	**1,119**	**998**	**1,079**
Total net production	**(boe/d)**	**37,244**	**36,255**	**34,505**	**36,753**	**34,124**

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. Disclosure of well-flow test results included in this MD&A is not necessarily indicative of long-term performance or of ultimate recovery. Where a pressure transient analysis or well-test interpretation has not yet been carried out, as indicated above, the data should be considered preliminary until such analysis or interpretation has been completed.

Abbreviations

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

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