FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

November 6, 2024

For the three and nine months ended September 30, 2024

*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 2000, 222 – 3rd Avenue SW, Calgary, Alberta, Canada, T2P 0B4.*

Legal Notice – Forward-Looking Information

*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 Consolidated Financial Statements and related notes for the three and nine months ended September 30, 2024 and 2023 (the "**Interim Condensed 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, actions of the Organization of Petroleum Exporting Countries ("**OPEC+**"), the impact of the Russia-Ukraine conflict and the conflict in the Middle East, the expected impact of measures that the Company has taken and continues to take in response to these events, the Company's strategic alternatives review process for its Colombian Infrastructure business and its interests in the Corentyne block in Guyana, the Company's belief that the value of its assets is not reflected in the current stock price and the ability of such strategic processes to drive value for shareholders, the Company's goal of enhancing shareholder value by returning capital to security holders, the Company's current intentions regarding commencement of the New SIB, the amount of capital returned to shareholders under the New SIB, the timing of completion of the New SIB, the terms of the New SIB and the Company's intention to announce further details regarding the New SIB, expectations with respect to the NCIB and regulatory approval thereof, the expectations regarding the 2024 production guidance, the timing of completion of the connection project between Puerto Bahia and Reficar, and Puerto Bahia's new LPG project; the future water handling capacity in CPE-6 and at SAARA, 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. In addition, no assurance can be given that such an agreement will be reached or the extent of the property covered by the Notice of Potential Commercial Interest outside of the area around the Wei-1 well.

The New SIB (as defined below) referred to in this MD&A has not yet commenced. This is for informational purposes only and does not constitute an offer to buy or the solicitation of an offer to sell Common Shares. The solicitation and the offer to buy Common Shares will only be made pursuant to a formal offer to purchase and issuer bid circular, a letter of transmittal, a notice of guaranteed delivery and other related documents to be filed with the applicable Canadian securities regulatory authorities. The offer to purchase pursuant to the New SIB (as defined below) will not be made to, nor will tenders be accepted from or on behalf of, holders of Common Shares in any jurisdiction in which the making or acceptance of offers to sell Common Shares would not be in compliance with the laws of that jurisdiction.

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 Russia-Ukraine conflict and the conflict in the Middle East; 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 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; the effectiveness of our restructuring plan; timing on receipt of government approvals; fluctuations in foreign exchange or interest rates and stock market volatility.

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

		Q3 2024	Q2 2024	Q3 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
Operational Results						
Heavy crude oil production [1]	(bbl/d)	25,312	24,839	24,097	24,520	23,480
Light and medium crude oil combined production [1]	(bbl/d)	12,794	12,583	13,964	12,653	15,214
Total crude oil production	(bbl/d)	38,106	37,422	38,061	37,173	38,694
Conventional natural gas production [1]	(mcf/d)	3,192	4,019	5,250	3,494	6,475
Natural gas liquids production [1]	(boe/d)	1,950	1,785	1,820	1,792	1,647
Total production [2]	(boe/d) [3]	40,616	39,912	40,802	39,578	41,477
Total inventory balance	(bbl)	1,315,384	1,319,189	1,330,418	1,315,384	1,330,418
Brent price reference	($/bbl)	78.71	85.03	85.92	81.82	81.94
Produced crude oil and gas sales [4]	($/boe)	71.11	78.31	80.34	75.03	74.21
Purchased crude net margin [4]	($/boe)	(3.05)	(2.13)	(1.86)	(2.54)	(2.24)
Oil and gas sales, net of purchases [4]	($/boe)	68.06	76.18	78.48	72.49	71.97
Premiums paid on oil price risk management contracts, net [5]	($/boe)	(0.45)	(1.32)	(0.59)	(0.99)	(0.83)
Royalties [5]	($/boe)	(0.91)	(2.01)	(3.76)	(1.50)	(3.38)
Net sales realized price [4]	($/boe)	66.70	72.85	74.13	70.00	67.76
Production costs (excluding energy cost), net of realized FX hedge impact [4]	($/boe)	(8.88)	(10.79)	(8.82)	(9.95)	(8.46)
Energy costs, net of realized FX hedge impact [4]	($/boe)	(5.11)	(4.74)	(5.04)	(5.05)	(4.31)
Transportation costs, net of realized FX hedge impact [4]	($/boe)	(12.12)	(10.92)	(11.73)	(11.46)	(11.27)
Operating netback per boe [4]	($/boe)	40.59	46.40	48.54	43.54	43.72
Financial Results						
Oil & gas sales, net of purchases [6]	($M)	214,084	218,528	254,805	635,081	665,143
Premiums paid on oil price risk management contracts, net	($M)	(1,425)	(3,796)	(1,930)	(8,710)	(7,705)
Royalties	($M)	(2,853)	(5,774)	(12,216)	(13,133)	(31,266)
Net sales [6]	($M)	209,806	208,958	240,659	613,238	626,172
Net income (loss) [7]	($M)	16,588	(2,846)	32,582	5,239	101,459
Per share – basic	($)	0.20	(0.03)	0.38	0.06	1.19
Per share – diluted	($)	0.19	(0.03)	0.37	0.06	1.16
General and administrative	($M)	12,719	12,928	11,925	39,203	37,016
Outstanding Common Shares	Number of Shares	84,167,856	84,253,816	85,431,716	84,167,856	85,431,716
Operating EBITDA [6]	($M)	103,184	110,321	137,800	310,753	346,183
Cash provided by operating activities	($M)	124,058	149,787	153,957	339,461	338,362
Capital expenditures [6]	($M)	82,411	80,198	74,130	231,990	360,442
Cash and cash equivalents – unrestricted	($M)	205,572	180,659	189,190	205,572	189,190
Restricted cash short and long-term [8]	($M)	34,752	34,419	32,048	34,752	32,048
Total cash [8]	($M)	240,324	215,078	221,238	240,324	221,238
Total debt and lease liabilities [8]	($M)	531,235	523,994	525,517	531,235	525,517
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [9]	($M)	415,387	426,004	409,853	415,387	409,853
Net debt (excluding Unrestricted Subsidiaries) [9]	($M)	267,043	283,651	271,508	267,043	271,508

(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 the 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 37.

(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 37.

(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.

(5) Supplementary financial measure (as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures” section on page 24.

(6) 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.

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

(8) Capital management measure (as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures” section on page 24.

(9) “**Unrestricted Subsidiaries**” include CGX Energy Inc. (“**CGX**”), listed on the TSX Venture Exchange under the trading symbol “OYL”, Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. (“**PIL**”), Frontera BIC Holding Ltd. and Frontera Bahía Holding Ltd. (“**Frontera Bahia**”), including Sociedad Portuaria Puerto Bahia S.A (“**Puerto Bahia**”). On April 11, 2023, Frontera Energy Guyana Holding Ltd. and Frontera Energy Guyana Corp. were designated as unrestricted subsidiaries. Refer to the “Liquidity and Capital Resources” section on page 30.

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 and 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.

Third Quarter of 2024

Frontera recorded another strong quarter generating net income of $16.6 million and delivering Operating EBITDA of $103.2 million in line with its plan, despite lower average Brent prices and certain unexpected events during the quarter. The Company remains on track to meet its 2024 Production and EBITDA Guidance.

During the quarter, the Company increased its quarter-over-quarter average daily production by 2% to 40,616 boe/d led by strong performance from the Company's heavy oil assets. The heavy oil assets performance was supported by successful drilling campaigns in both the CPE-6 and Sabanero blocks, and increased water disposal capacity in the CPE-6 block, where the Company achieved another daily production record reaching 8,810 bbl/d. These gains were offset mainly by the effects of the 6-day national truckers strike and blockades.

Light and medium crude oil production increased, driven by increased production in Ecuador and well intervention activity performed during the first half of the year which helped maintain light and medium crude production levels. The natural gas liquids production during the quarter increased following the completion and start-up of the compression facilities expansion and gas reinjection project at our VIM-1 block. Following the completion of the VIM-1 gas reinjection project, natural gas volumes produced at VIM-1 were reinjected reducing natural gas production and sales volumes. Exploration activities for the VIM-1 block are expected to resume in early 2025 with the drilling of the Hidra-1 well following delays during 2024 associated to social issues. We continue to see additional activity on our VIM-1 block and remain excited about its prospects.

October 2024's actual average daily production totaled 42,300 boe/d.

The Company invested approximately $82.4 million in capital expenditures during the quarter primarily to drill 15 development wells at Quifa, CPE-6 and Sabanero, as well as to improve facilities and flowlines.

Additionally, as part of the Company's continuing drive to simplify the business, Frontera and the ANH also mutually agreed to terminate the legacy Caguan 5 and Caguan 6 blocks exploration contracts reducing the Company's commitments by approximately $53 million related to exploration areas with long-standing social and security limitations.

In the infrastructure business, Oleoducto de los Llanos Orientales S.A. ("**ODL**") continues to deliver positive operational and financial results, generating $68 million of EBITDA for the quarter, resulting in $12.2 million in net distributions to Frontera during the quarter (totaling $43.5 million year-to-date). In Puerto Bahia, construction of the connection to the Reficar refinery is over 60% complete, and the Company is confident that the connection shall become operational by the end of the year. With respect to our LPG import project, working groups have been assembled and detailed engineering work is underway.

In the SAARA project, developed by Frontera's wholly owned subsidiary Agro Cascada S.A.S. ("**Agro Cascada**"), the Company is currently processing approximately 50,000 barrels of water per day, and expect to grow water handling capacity to 250,000 barrels by year-end, boosting heavy crude oil production at the Quifa block. In addition, on October 10, 2024, Citibank disbursed COP$ 29,330 million (roughly $7 million) to Agro Cascada.

Environmental, Social, and Governance

In 2024, Frontera has achieved 73% of its sustainability goals. In the third quarter, Frontera made purchases to local suppliers that represent 10,8% of its total purchases. These results exceed the annual goal of 9%.

Additionally, our efforts to maintain close and empathic relationships with all our stakeholders including our employees, Frontera was recognized with "the Great Place to Work" award and ranked 17th as one of the best companies to work in Colombia.

Our work plan in favor of cybersecurity has been effective, and we have managed to maintain our rate of material cybersecurity incidents at 0.

Enhancing Investors Returns

So far in 2024, Frontera has delivered on its commitment to enhance shareholder returns. Subsequent to the quarter and with significant shareholder take-up, the Company successfully completed on its $30.0 million Substantial Issuer Bid ("**SIB**") which saw over 90% of the Company's shareholders participate. More importantly, and together with the successful SIB, the Company will have returned in excess of $53 million to its Shareholders, including $11.7 million of declared and paid quarterly dividends, $3.9 million in declared quarterly dividends and repurchased repurchased $7.8 million of its common shares through its NCIB (as defined below), for an estimated aggregate yield of 11%. The Company has also repurchased $5 million of its 2028 senior unsecured notes.

Consistent with the Company's shareholder value focus and following the strong third quarter results, the Company is pleased to announce its intention to commence a new substantial issuer bid (the "**New SIB**") to purchase up to $30 million of the Company's outstanding shares. The Company shall continue to consider future investors initiatives, including potential additional dividends, distributions, or bond buybacks, based on the overall results of the businesses, cash flow generation and the Company's strategic goals.

Unlocking Value from the Sum of Its Parts

Together with the financial advisor, Goldman Sachs, the Company continues to advance its strategic alternatives review efforts for its standalone and growing Colombian Infrastructure business. This process is actively ongoing with a virtual data room open and discussions with interested third parties underway. The Company remains particularly excited about the long-term prospects of its port business, Puerto Bahia, and its strong pipeline of catalysts including the Reficar connection as well as the recently announced LPG import project with its JV partner, Gasco Soluciones Logísticas y Energéticas S.A.S. ("**GASCO**").

With respect to its Guyana assets, the Company and its joint venture partner remain committed to the potential development of the Corentyne block as supported by the recent discoveries. While the Company continues to remain confident about the potential of the Corentyne block, the Company is reviewing all available alternatives to safeguard its interest in the block and Guyana.

Subsequent to the quarter, S&P reaffirmed the Company's credit rating at B with a Stable Outlook, reflecting Frontera's the strong credit quality and financial position, underpinned by the Company's low leverage. The Company ended this quarter with total debt of $531.2 million and a healthy cash position (including restricted cash) of $240.3 million.

These strategic alternatives review processes are central to the Company's efforts to streamline its business and unlock the inherent value from the sum of its parts and drive value for shareholders. There can be no assurance that these strategic review processes will result in a transaction.

Financial and Operational Results

- Production averaged 40,616 boe/d in the third quarter of 2024 (consisting of 25,312 bbl/d of heavy crude oil, 12,794 bbl/d of light and medium crude oil combined, 3,192 mcf/d of conventional natural gas and 1,950 boe/d of natural gas liquids), compared to 39,912 boe/d in the prior quarter (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), and compared to 40,802 boe/d in the third quarter of 2023 (consisting of 24,097 bbl/d of heavy crude oil, 13,964 bbl/d of light and medium crude oil combined, 5,250 mcf/d of conventional natural gas and 1,820 boe/d of natural gas liquids).

- Cash provided by operating activities was $124.1 million in the third quarter of 2024, compared with $149.8 million in the prior quarter, and $154.0 million in the third quarter of 2023. The Company reported a total cash position of $240.3 million, including $34.8 million of restricted cash, as at September 30, 2024, compared with a total cash position of $215.1 million, including $34.4 million of restricted cash, as at June 30, 2024, and $221.2 million, including $32.0 million of restricted cash, as at September 30, 2023.

- The Company recorded a net income(1) of $16.6 million ($0.19/share(2)) in the third quarter of 2024, compared with net loss(1) of $2.8 million ($0.03/share(2)) in the prior quarter and net income(1) of $32.6 million ($0.37/share(2)) in the third quarter of 2023.

- Capital expenditures were $82.4 million in the third quarter of 2024, compared with $80.2 million in the prior quarter and $74.1 million in the third quarter of 2023.

- Operating EBITDA was $103.2 million in the third quarter of 2024, compared with $110.3 million in the prior quarter and $137.8 million in the third quarter of 2023.

- Operating netback was $40.59/boe in the third quarter of 2024, compared with $46.40/boe in the prior quarter and $48.54/boe in the third quarter of 2023.

- Infrastructure Colombia Segment (as defined below) income was $13.1 million in the third quarter of 2024, compared with $14.6 million in the prior quarter and $14.0 million in the third quarter of 2023.

- Adjusted Infrastructure EBITDA in the third quarter of 2024 was $26.2 million, compared with $27.8 million in the prior quarter and $26.9 million during the third quarter of 2023.

- Puerto Bahia liquids volumes handled during the third quarter of 2024 were 46,964 bbl/d compared to 61,798 bbl/d in the prior quarter and 53,586 bbl/d in the third quarter of 2023. Puerto Bahia revenues were $9.7 million during the third quarter of 2024, compared to $11.2 million in the prior quarter and $12.3 million during the third quarter of 2023.

- ODL volumes transported were 243,997 bbl/d during the third quarter of 2024, compared to 249,196 in the second quarter of 2024, mainly due to lower production from Llanos 34 transported through the pipeline.

(1) Net income (loss) attributable to equity holders of the Company.
(2) Per Common Share on a diluted basis.

2. GUIDANCE

The following table reports the Company's actual results for the nine months ended September 30, 2024, against the full year 2024 guidance metrics as released on February 15, 2024.

Despite some inflationary cost pressures, we remain on track to achieve our 2024 capital, production and EBITDA guidance. We have increased production during the quarter with actual average daily production for October of approximately 42,300 boe/d, and targeting a fourth quarter average daily production above 42,500 boe/d.

		2024	
		Guidance	**Actual**
Average Daily Production(1)	boe/d	40,000 - 42,000	39,578
Production Costs (excluding energy cost) (2)(4)	$/boe	8.50 - 9.50	9.95
Energy Costs (2)(4)	$/boe	5.75 - 6.25	5.05
Transportation Costs(3)(4)	$/boe	11.00 - 12.00	11.46
Operating EBITDA(5) at $80/bbl (6)	$MM	400 - 450	310.8
Adjusted Infrastructure EBITDA(7)	$MM	95 - 115	79.7
Development Drilling	$MM	85 - 95	102.9
Development Facilities (8)	$MM	95 - 115	69.0
Colombia and Ecuador Development	$MM	180 - 210	171.9
Colombia and Ecuador Exploration	$MM	35 - 45	21.0
Other (9)	$MM	15 - 25	14.5
Total Colombia & Ecuador Upstream Capex	$MM	230 - 280	207.4
Colombia Infrastructure(10)	$MM	40 - 50	21.9
Guyana Exploration	$MM	2 - 5	2.7
Total Capital Expenditures(11)	$MM	272 - 335	232.0

(1) The Company's 2024 average production guidance range does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2024.
(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 National Instrument 52-112 - Non-GAAP and Other Financial Measures ("NI 52-112")). Refer to the "Non-IFRS and Other Financial Measures".
(5) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). "Operating EBITDA" represents the operating results of the Company's business, excluding the following items: restructuring, severance and other costs, certain non-cash items and gains or losses arising from the disposal of capital assets. Refer to the "Non-IFRS and Other Financial Measures".
(6) Current Guidance Operating EBITDA calculated at Brent $80/bbl and COP/USD exchange rate of 4,100:1.
(7) Reported Adjusted Infrastructure EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the infrastructure business, including the proportional consolidation of the 35% equity investment in the ODL pipeline.
(8) Investments related to the replacement and repairs of the affected assets in the Quifa Block due to unexpected failures in a trunkline, are not included in either the actual results or the Guidance.
(9) Other includes Sabanero Insurance, HSEQ activities and New Technologies.
(10) Colombia Infrastructure includes investments related to the connection of Puerto Bahia's port facility and the Cartagena refinery (the "**Reficar Connection Project**") operated by Refineria de Cartagena S.A.S. ("**Reficar**"), the SAARA reverse osmosis water treatment facility, and safety, maintenance activities and operational optimizations in the port.
(11) 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". Capital expenditures excludes decommissioning.

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 37 for details of the Company's net production:

		Production				
					Nine months ended September 30	
Producing blocks in Colombia		**Q3 2024**	**Q2 2024**	**Q3 2023**	**2024**	**2023**
Heavy crude oil	(bbl/d)	25,312	24,839	24,097	24,520	23,480
Light and medium crude oil combined	(bbl/d)	11,018	10,928	13,312	11,016	14,459
Conventional natural gas	(mcf/d)	3,192	4,019	5,250	3,494	6,475
Natural gas liquids	(boe/d)	1,950	1,785	1,820	1,792	1,647
Total production Colombia	**(boe/d)**	**38,840**	**38,257**	**40,150**	**37,941**	**40,722**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,776	1,655	652	1,637	755
Total production Ecuador	**(bbl/d)**	**1,776**	**1,655**	**652**	**1,637**	**755**
Total production	**(boe/d)**	**40,616**	**39,912**	**40,802**	**39,578**	**41,477**

Colombia

For the three months ended September 30, 2024, production in Colombia increased by 583 boe/d, compared to the prior quarter.

Heavy crude oil production increased by 2% due to successful development drilling campaigns in the CPE-6, Sabanero and Quifa blocks, and increased water disposal capacity in the CPE-6 Block. This increase was affected mainly by the effects of the 6-day national truckers strike and blockades. Light and medium crude oil production increased, driven by well intervention activity performed during the first half of the year which helped maintain light and medium production levels. Natural gas liquids production during the quarter increased following the completion and start-up of the compression facilities expansion and gas reinjection project at the VIM-1 Block. Following the completion of the VIM-1 gas reinjection project, natural gas volumes produced at VIM-1 were reinjected reducing natural gas production and sales volumes.

Compared to the three and nine months ended September 30, 2023, total production in Colombia decreased by 1,310 boe/d and 2,781 boe/d, respectively, as a result of the following: (i) heavy crude oil production increased by 1,215 bbl/d and 1,040 bbl/d, respectively, as a result of the successful development drilling campaigns in the CPE-6 and Sabanero blocks, the new water facilities in the CPE-6 Block, and the reactivation of wells in the Sabanero Block. In addition, in fourth quarter, the Company aims to increase processing capacity at SAARA to 250 Mbbl, which support higher production levels from the Quifa Block; (ii) natural gas liquids production increased by 7% and 9% due to the increased production of the VIM-1 Block as a result of the development of the facilities, partially offset by natural decline; (iii) light and medium crude oil combined, decreased by 17% and 24%, respectively, and conventional natural gas production decreased by 39% and 46%, respectively. These declines in production were primarily attributed to natural declines in the El Dificil Block and the Neiva Block production contract that ended in June 2023, which had contributed 417 boe/d.

Ecuador

Total production in Ecuador for the three and nine months ended September 30, 2024, increased by 172% and 117%, respectively, in the light and medium crude oil combined, compared to the same periods of 2023. This increased was attributed to the drilling and completion of three wells in the Perico Block during the second half of 2023 and an additional three wells in 2024, as well as two exploration wells drilled in the Espejo in June 2024.

Compared to the prior quarter, the production increase mainly due to the completion of one exploration well in June 2024.

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 sale volumes, net of purchases and summarizes other factors that impacted total sales volumes:

					Nine months ended September 30	
		Q3 2024	Q2 2024	Q3 2023	2024	2023
Production	(boe/d)	**40,616**	**39,912**	**40,802**	**39,578**	**41,477**
Royalties in-kind Colombia	(boe/d)	(4,788)	(4,871)	(4,093)	(4,558)	(4,160)
Royalties in-kind Ecuador [1]	(boe/d)	(561)	(536)	(192)	(512)	(223)
Net production	(boe/d)	**35,267**	**34,505**	**36,517**	**34,508**	**37,094**
Oil inventory (build) draw	(boe/d)	42	(444)	1,131	(872)	(336)
Volumes purchased	(boe/d)	8,161	6,830	6,246	7,783	7,302
Other inventory movements [2]	(boe/d)	(2,250)	(2,797)	(1,841)	(2,502)	(2,384)
Sales volumes	(boe/d)	**41,220**	**38,094**	**42,053**	**38,917**	**41,676**
Sale of volumes purchased	(boe/d)	(7,028)	(6,571)	(6,764)	(6,943)	(7,821)
Sales volumes, net of purchases	(boe/d)	**34,192**	**31,523**	**35,289**	**31,974**	**33,855**
Oil sales volumes	(bbl/d)	33,651	30,816	34,206	31,367	32,687
Conventional natural gas sales volumes	(mcf/d)	3,084	4,030	6,173	3,462	6,658
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**34,192**	**31,523**	**35,289**	**31,974**	**33,855**
Inventory balance						
Colombia [3]	(bbl)	777,158	758,794	812,797	777,158	812,797
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	58,026	80,195	37,421	58,026	37,421
Inventory ending balance	**(bbl)**	**1,315,384**	**1,319,189**	**1,330,418**	**1,315,384**	**1,330,418**

[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 0.33 MMbbl of oil produced and 0.45 MMbbl of diluent in the third quarter of 2024, 0.41 MMbbl of oil produced and 0.35 MMbbl of diluent in the second quarter of 2024, and 0.62 MMbbl of oil produced and 0.19 MMbbl of diluent the third quarter of 2023.

Sales volumes, net of purchases, for the three months ended September 30, 2024, increased by 8% compared with the prior quarter, due to additional oil and gas production and inventory draw. Compared with the same quarter of 2023, sales decreased by 3%, mainly due to lower light and medium oil net production and lower inventory draw in 2024. For the nine months ended September 30, 2024, sales decreased by 6%, compared with the same period of 2023, due to lower light and medium oil production.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo and CPE-6 blocks. In February 2023, the ANH changed the payment method for PAP payments, requiring in-kind payments for all blocks, except for the CPE-6, Guatiquia (Yatay field) and Cubiro (Copa A field) blocks. In October 2023, the ANH made an additional change in the payment method for PAP payments, by requiring in-kind payments for the CPE-6 Block.

The PAP is applicable once accumulated production has exceeded 5 MMbbl (commercial area for the Quifa Block, and exploitation area for exploration and production contracts) and escalates as oil prices increase above a minimum contractual baseline WTI price, which is adjusted yearly by the U.S. Producer Price Index. Increases in oil prices can trigger higher PAP obligations, payable both in-kind (reducing the Company's net production) and in cash (increasing royalties).

					Nine months ended September 30	
		Q3 2024	Q2 2024	Q3 2023	2024	2023
PAP in kind	(bbl/d)	1,658	2,050	1,791	1,678	1,852
PAP in cash	(bbl/d)	338	402	788	372	771
PAP	**(bbl/d)**	**1,996**	**2,452**	**2,579**	**2,050**	**2,623**
% Production		**4.9 %**	**6.1 %**	**6.3 %**	**5.2 %**	**6.3 %**

For the three and nine months ended September 30, 2024, the total PAP decreased compared with the same periods of 2023, mainly due to lower light and medium crude oil production.

During the third quarter of 2024, PAP in kind decreased compared to the same period of 2023, mainly due to the lower light and medium crude oil production and lower WTI oil benchmark price. Compared to the prior period, PAP in kind decreased due to lower WTI oil benchmark price.

For the three and nine months ended September 30, 2024, PAP in cash decreased compared with the same periods of 2023, mainly due to the change in the payment method required by ANH, as mentioned above, and compared with the prior quarter, PAP in cash decreased mainly due to a lower WTI oil benchmark price.

Realized and Reference Prices

					Nine months ended September 30	
		Q3 2024	Q2 2024	Q3 2023	2024	2023
Reference price						
Brent [1]	($/bbl)	78.71	85.03	85.92	81.82	81.94
Average realized prices						
Realized oil price, net of purchases	($/bbl)	68.53	77.16	80.08	73.20	73.49
Realized conventional natural gas price	($/mcf)	6.77	5.88	4.91	6.27	5.17
Net sales realized price						
Produced crude oil and gas sales [2]	($/boe)	71.11	78.31	80.34	75.03	74.21
Purchased crude net margin [2]	($/boe)	(3.05)	(2.13)	(1.86)	(2.54)	(2.24)
Oil and gas sales, net of purchases [2]	($/boe)	68.06	76.18	78.48	72.49	71.97
Premiums paid on oil price risk management contracts, net [3] [4]	($/boe)	(0.45)	(1.32)	(0.59)	(0.99)	(0.83)
Royalties [3]	($/boe)	(0.91)	(2.01)	(3.76)	(1.50)	(3.38)
Net sales realized price [2]	**($/boe)**	**66.70**	**72.85**	**74.13**	**70.00**	**67.76**

(1) Frontera's weighted average Brent price for the three and nine months ended September 30, 2024, was $77.95/bbl and $81.33/bbl, respectively.
(2) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24. Corresponds to the net sales and costs of third-party hydrocarbon volumes purchased primarily for dilution and refining purpose, as part of the Company's oil operations, marketing and transportation strategy.
(3) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24.
(4) Includes put premiums paid for the position expired during the period.

The average Brent benchmark oil price during the three and nine months ended September 30, 2024, decreased by 8% and 0.1%, respectively, compared to the same periods of 2023. In comparison to the second quarter of 2024, the average Brent benchmark oil price decreased by 7%. The decrease in crude oil prices during 2024 compared with the same period of 2023, was mainly due to: (i) weak demand in China (ii) high inflation in the USA, which kept interest rates unchanged, and iii) the OPEC+ decision to being increasing production by 180 Mbbl/d per month starting in December 2024 until the end of next year, affecting the supply side.

For the nine months ended September 30, 2024 the Company's net sales realized price increased $2.24/boe, compared to the same period of 2023, driven by lower royalties and better oil differential prices, partially offset by premiums paid on oil price risk management contracts.

For the three months ended September 30, 2024, the Company's net sales realized price was $66.70/boe. This represents a decrease of 8% compared to the prior quarter and 10% compared to the same period of 2023. The decrease was driven by a lower Brent benchmark oil price, an increase in oil differential prices, partially offset by lower royalties paid in cash and lower premiums paid on oil price risk management contracts.

Operating Netback

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

	Q3 2024		Q2 2024		Q3 2023	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	209,806	66.70	208,958	72.85	240,659	74.13
Production costs (excluding energy cost), net of realized FX hedge impact (1)(2)(3)	(33,164)	(8.88)	(39,198)	(10.79)	(33,103)	(8.82)
Energy costs, net of realized FX hedge impact (1)(2)(4)	(19,103)	(5.11)	(17,227)	(4.74)	(18,912)	(5.04)
Transportation costs, net of realized FX hedge impact (1)(2)(5)	(39,334)	(12.12)	(34,283)	(10.92)	(39,422)	(11.73)
Operating Netback (1) (2)	**118,205**	**40.59**	**118,250**	**46.40**	**149,222**	**48.54**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases (6)		34,192		31,523		35,289
Production (7)		40,616		39,912		40,802
Net production (8)		35,267		34,505		36,517

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.
(3) Includes a realized FX hedge loss of $0.2 million attributable to production costs for the third quarter of 2024 and a realized FX hedge gain of $2.2 million and $2.1 million, attributable to production costs for the second quarter of 2024, and the third quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(4) Includes a realized FX hedge loss of $0.1 million, attributable to energy costs for the third quarter of 2024 and a realized FX hedge gain of $0.8 million and $0.8 million attributable to energy costs for the second quarter of 2024, and the third quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(5) Includes a realized FX hedge loss of $0.1 million, attributable to transportation costs for the third quarter of 2024, and a realized FX hedge gain of $0.6 million and $0.7 million attributable to transportation costs for the second quarter of 2024, and the third quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(6) Sales volumes, net of purchases, excluding sales of third-party volumes.
(7) Refer to the "Production" section on page 6.
(8) Refer to the "Further Disclosures" section on page 37.

The Company's operating netback for the third quarter of 2024 was $40.59/boe, compared to $48.54/boe in the same quarter of 2023. In comparison to the second quarter of 2024, the Company's operating netback decreased 13%, from $46.40/boe to $40.59/boe, mainly due to lower net sales realized prices; an increase in transportation costs, net of realized FX hedge impact, was primarily attributed to pipeline and truck tariffs increases that occurred during the quarter and higher volumes transported; higher energy costs, net of realized FX hedge impact, was as a result of higher energy use related to the increase in heavy crude oil production; partially offset by a reduction in production costs (excluding energy costs), net of realized FX hedge impact, by lower well intervention activities in the light and medium assets during the quarter.

The following table provides a summary of the Company's netbacks for the nine months ended September 30, 2024, and 2023:

	Nine months ended September 30			
	2024		2023	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	613,238	70.00	626,172	67.76
Production costs (excluding energy cost), net of realized FX hedge impact (1)(2)(3)	(107,864)	(9.95)	(95,821)	(8.46)
Energy costs, net of realized FX hedge impact (1)(2)(4)	(54,717)	(5.05)	(48,757)	(4.31)
Transportation costs, net of realized FX hedge impact (1)(2)(5)	(108,403)	(11.46)	(114,155)	(11.27)
Operating Netback (1) (2)	**342,254**	**43.54**	**367,439**	**43.72**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases (6)		31,974		33,855
Production (7)		39,578		41,477
Net production (8)		34,508		37,094

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.
(3) Includes $3.4 million and $7.0 million of realized FX hedge gain attributable to production costs for the nine months ended September 30, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(4) Includes $1.3 million and $2.1 million of realized FX hedge gain attributable to energy costs for the nine months ended September 30, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(5) Includes $1.0 million and $2.5 million of realized FX hedge gain attributable to transportation costs for the nine months ended September 30, 2024, and 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 14.
(6) Sales volumes, net of purchases, excluding sales of third-party volumes.
(7) Refer to the "Production" section on page 6.
(8) Refer to the "Further Disclosures" section on page 37.

Operating netback for the nine months ended September 30, 2024, was comparable in relation to the same period of 2023. The changes were primarily due to an increase in production costs (excluding energy cost), net of realized FX hedge impact, mainly as a result of higher well services activity, inflationary pressures on services and wages indexation, higher energy cost, net of realized FX hedge impact, due to an increase in market prices related to El Niño-related events, and transportation costs mainly due to the annual pipeline tariffs increases, partially offset by higher net sales realized price.

Sales

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Produced crude oil sales	221,757	258,041	651,421	676,449
Purchased crude net margin	(9,594)	(6,023)	(22,286)	(20,699)
Conventional natural gas sales	1,921	2,787	5,946	9,393
Oil and gas sales, net of purchases [(1)]	214,084	254,805	635,081	665,143
Premiums paid on oil price risk management contracts [(2)]	(1,425)	(1,930)	(8,710)	(7,705)
Royalties	(2,853)	(12,216)	(13,133)	(31,266)
Net sales [(1)]	**209,806**	**240,659**	**613,238**	**626,172**
Net sales realized price ($/boe) [(3)]	66.70	74.13	70.00	67.76

(1) Non-IFRS financial measure. Refer to the “Non-IFRS and Other Financial Measures’’ section on page 24.
(2) Includes put premiums paid for the position expired during the period.
(3) Non-IFRS ratio. Refer to the “Non-IFRS and Other Financial Measures’’ section on page 24.

Oil and gas sales, net of purchases, decreased by $40.7 million for the three months ended September 30, 2024, compared to the same period of 2023, mainly due to lower volumes sold, lower Brent benchmark oil price (Refer to the “Realized and Reference Prices” section on page 8 for further details on changes in prices), higher oil differential prices and higher purchased crude net margin. For the nine months ended September 30, 2024, oil and gas sales, net of purchases, decreased by $30.1 million compared to the same period of 2023, mainly due to lower volumes sold, a lower Brent benchmark oil price partially offset by better oil differential prices, and higher purchased crude net margin.

Net sales for the three and nine months ended September 30, 2024, decreased by $30.9 million and $12.9 million, respectively, compared with the same periods of 2023. The following table describes the various factors that impacted net sales:

	Three months ended September 30	Nine months ended September 30
($M)	**2024-2023**	**2024-2023**
Net sales for the period ended September 30, 2023	240,659	626,172
Decreased due to -13% lower oil and gas price (YTD 1% higher)	(33,847)	4,806
Decrease due to variance of total produced volumes sold	(6,874)	(34,868)
Decrease in royalties	9,363	18,133
Decrease (increase) in premiums paid on oil price risk management contracts	505	(1,005)
Net sales for the period ended September 30, 2024	**209,806**	**613,238**

Oil and Gas Operating Costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Production costs (excluding energy cost)	32,395	35,237	110,635	102,795
Energy cost	19,019	19,705	55,984	50,919
Transportation costs	39,273	40,166	109,385	116,666
Post-termination cost	(314)	1,377	(128)	7,654
Inventory valuation	3,857	1,178	(1,086)	(7,436)
Trunkline costs	3,829	—	3,829	—
Total oil and gas operating costs	**98,059**	**97,663**	**278,619**	**270,598**

During the three and nine months ended September 30, 2024, total oil and gas operating costs increased by $0.4 million and $8.0 million respectively, compared to the same periods of 2023. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs (excluding energy cost) for the three months ended September 30, 2024, decreased 8% compared with the same period of 2023, primarily due to lower maintenance costs. For the nine months ended September 30, 2024 production costs (excluding energy cost) increased 8% compared with the same period of 2023, mainly as a result of higher well services activity.

- Energy cost for the three months ended September 30, 2024, decreased 3% compared with the same period of 2023, mainly due to lower market prices. For the nine months ended September 30, 2024, Energy Cost increased 10% compared with the same period of 2023, mainly due to higher energy use related to the increase in heavy crude oil production.
- For the three and nine months ended September 30, 2024, transportation costs decreased 2% and 6%, respectively, compared with the same periods of 2023, primarily due to lower volumes produced and transported and partially offset by annual pipeline tariffs increments.
- Post-termination obligations for the three and nine months ended September 30, 2024, was negative by $0.3 million and $0.1 million respectively, as a result of cost efficiencies in the execution of activities from returned blocks and partially offset by the accrual of costs for the relinquished Block 192 in Peru.
- Inventory valuation for the three and nine months ended September 30, 2024, increased by $2.7 million and $6.4 million respectively compared with the same periods of 2023, mainly as a result of inventory draw.
- Trunkline costs corresponds to repairs and other activities resulting from unexpected failures in a trunkline in Quifa Block, which has already been resolved. The Company expects to recover a portion of these costs from the proceeds of claims on its material damages and third-party liability insurance policies.

Cost of Diluent and Oil Purchased

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Cost of diluent and oil purchased	57,557	54,555	170,569	180,444

(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.

Cost of diluent and oil purchased correspond to the cost of third-party hydrocarbon volumes purchased primarily for dilution and refining usage as part of the Company’s oil operations, and marketing and transportation strategy. For the three months ended September 30, 2024, the cost of diluent and oil purchased, including the transportation and processing fees for volumes sold, increased by $3.0 million, compared with the same period of 2023, primarily due to a reduction in light and medium oil production and an increase in heavy oil production, which demands higher volumes of diluent and fuel used for energy, partially offset by volumes sold of a new heavy crude oil blend, which requires less diluent, transported to Puerto Bahia.

For the nine months ended September 30, 2024, the cost of diluent and oil purchased, including the transportation and processing fees for volumes sold, decreased by $9.9 million, compared with the same period of 2023, mostly by volumes sold of a new heavy crude oil blend, which requires less diluent, transported to Puerto Bahia and higher quality diluent acquired, partially offset by an increase in heavy oil production volumes.

Royalties

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Royalties Colombia	2,412	12,033	12,105	30,690
Royalties Ecuador	441	183	1,028	576
Royalties	**2,853**	**12,216**	**13,133**	**31,266**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three and nine months ended September 30, 2024, royalties decreased by $9.4 million and $18.1 million, respectively, compared to the same periods of 2023, due to the change in the royalties payment method from in-cash to in-kind as per the ANH’s request, and a lower WTI oil benchmark price. Refer to the “Production Reconciled to Sales Volumes” section on page 7 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

($M)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Depletion, depreciation and amortization	68,269	61,756	197,269	209,858

For the three months ended September 30, 2024, depletion, depreciation, and amortization expense ("**DD&A**") increased 11% compared to the the same period of 2023, mainly due to a higher depletable base as a result of the transfer of the Perico Block to Oil & Gas properties at the end of 2023 and the expansion of the development facilities increasing of water-handling capacity at CPE-6 Block. For the nine months ended September 30, 2024, decreased 6% due to lower production during 2024 and the end of the Neiva Block production contract in June 2023.

Impairment Expense, Exploration Expenses and Others

($M)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Impairment expense of:				
Exploration and evaluation assets	—	—	—	19,503
Other	361	2,342	1,780	4,316
Total impairment expense	361	2,342	1,780	23,819
Exploration expenses of:				
Geological and geophysical costs, and other	384	435	1,198	1,214
Total exploration expenses	384	435	1,198	1,214
Expense (recovery) of asset retirement obligations	5,546	3,480	4,549	(24,001)
Impairment expense, exploration expenses and other	**6,291**	**6,257**	**7,527**	**1,032**

Total impairment expenses

During the three and nine months ended September 30, 2024, the total impairment expenses was $0.4 million and $1.8 million, respectively, mainly related to obsolete material inventories and impairment of crude oil inventories from Peru, compared to $2.3 million and $23.8 million, respectively, during same periods of 2023, which includes mainly an impairment charge on exploration and evaluation of assets in Colombia, as a result of the relinquishment of the VIM-22 Block.

Expense (recovery) of asset retirement obligation

When a decrease in the asset retirement obligations exceeds the carrying amount of the related asset, or there is an increase in the asset retirement obligations related to fully impaired or relinquished assets, the change is recognized as a recovery or expense of asset retirement obligations.

During the three and nine months ended September 30, 2024, the Company recognized an expense of asset retirement obligations of $5.5 million and 4.5 million, respectively. During the three and nine months ended September 30, 2023, the Company recognized an expense of asset retirement of $3.5 million and a recovery of asset retirement obligations of $24.0 million, respectively, mainly as a result of the sale of Frontera Energy OffShore Perú S.R.L, the wholly owned subsidiary that held a 100% W.I. in Block Z1, for a payment of $7.5 million. As a result of this transaction, the Company derecognized the asset retirement obligation related to Block Z1 and recognized a $37.4 million asset retirement obligation recovery.

Other Operating Costs

($M)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
General and administrative	12,719	11,925	39,203	37,016
Special projects and other cost [1]	2,907	2,916	6,841	8,345
Share-based compensation	680	1,018	1,720	1,893
Restructuring, severance and other costs	361	1,407	3,216	4,804

[1] Mainly includes costs related to SAARA, including the commissioning period during 2023, and Peru.

General and Administrative ("G&A")

For the three and nine months ended September 30, 2024, G&A expenses increased by 7% and 6%, respectively, compared with the same periods of 2023, mainly due to higher professional fees.

Special projects and other costs

For the three months ended September 30, 2024, special projects and other costs were comparable to the same period in 2023. Compared to the nine months ended September 30, 2023, decreased 18%, mainly due a reduction in costs related to Block Z1, due to the sale of Frontera Energy Off Shore Perú S.R.L., in 2023.

Share-Based Compensation

For the three and nine months ended September 30, 2024, share-based compensation decreased by $0.3 million and $0.2 million, respectively, compared with the same periods of 2023. The decrease for the three months ended September 30, 2024, was primarily due to a lower stock price, which reduced the intrinsic value of the shares granted to employees. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units ("**RSUs**") and grants of deferred share units ("**DSUs**") under the Company's security-based compensation plan, which are subject to variability from movements in the underlying Common Share trading price, and the consolidation of stock option expenses from the Company's indirect majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three and nine months ended September 30, 2024, restructuring, severance and other costs decreased by $1.0 million and $1.6 million, respectively, compared with the same periods of 2023, mainly due to a decrease in professional fees associated with restructuring initiatives.

Non-Operating Costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Finance income	3,126	1,941	6,534	7,714
Finance expenses	(17,696)	(16,411)	(52,395)	(47,320)
Foreign exchange (loss) income	(631)	4,305	(9,246)	9,551
Other (loss) income	(4,292)	(1,207)	(7,425)	4,382

Finance Income

For the three and nine months ended September 30, 2024, finance income increased by $1.2 million and decreased by $1.2 million, respectively, compared to the same periods of 2023. The increase was mainly due to the tax refund bonds ("TIDIS" for its acronym in Spanish) received and average of cash balances during the period, while the decrease was mainly due to a variation of interest rates on the investment trust accounts for abandonment requirements.

Finance Expenses

For the three and nine months ended September 30, 2024, finance expenses increased by $1.3 million and $5.1 million, respectively, compared to the same periods of 2023, mainly due to higher interest resulting from the Bancolombia Working Capital Loan (as defined below) and additional interest resulting from lease liabilities.

Foreign Exchange (Loss) Income

For the three and nine months ended September 30, 2024, foreign exchange loss of $0.6 million and $9.2 million, respectively, as a result of the transfer from the cumulative translation adjustment of the Other Comprehensive (Loss) Income ("**OCI**") to Consolidated Statement of Income of a return of capital and dividends of ODL during the first half of 2024. During the same period of 2023, the foreign exchange income was $4.3 million and $9.6 million, respectively, as a result of the COP's depreciation against the USD on the translation of the debt consolidated from Puerto Bahia during the first quarter 2023, offset by the transfer from the cumulative translation adjustment of the OCI to Consolidated Statement of Income of a return of capital of ODL for $6.8 million. Foreign exchange rates (COP:USD) as of September 30, 2024, and 2023, were 4,164.21:1 and 4,053.76:1, respectively.

Other (Loss) Income

For the three and nine months ended September 30, 2024, the Company recognized other loss of $4.3 million and $7.4 million respectively. These expenses were mainly attributable to contingencies, partially offset by income related to insurance compensation for the Sabanero Block. During the same periods of 2023, the Company recognized other loss of $1.2 million and an income $4.4 million, respectively. During the third quarter of 2023, the loss was mainly due to expenses related to blocks relinquished, and for the nine months ended September 30, 2023, the amount includes the net of the contingencies in the reversal of the legal claim from the late delivery of production from the Quifa Block prior to 2014.

Gain (Loss) on Risk Management Contracts

($M)	Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
Premiums paid on oil price risk management contracts, net	(1,425)	(1,930)	(8,710)	(7,705)
Realized (loss) gain on foreign exchange risk hedge [(1)]	(417)	4,112	6,030	13,070
Realized (loss) gain on risk management contracts	(1,842)	2,182	(2,680)	5,365
Unrealized gain (loss) on risk management contracts	7,644	(4,002)	(3,941)	4,880
Total gain (loss) on risk management contracts	5,802	(1,820)	(6,621)	10,245

(1) For determination of operating netback, during the three and nine months ended September 30, 2024, the Company estimates an attribution of $0.2 million and $3.4 million, respectively, of the total realized FX hedge to production cost (excluding energy cost) (2023: $2.1 million and $7.0 million respectively), estimates an attribution of $0.1 million and $1.3 million, respectively, of the total realized FX hedge to energy (2023:$0.8 million and $2.1 million, respectively), and estimates an attribution of $0.1 million and $1.0 million, respectively, of the total realized FX hedge to transportation (2023: $0.7 million and $2.5 million), respectively. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.

For the three months ended September 30, 2024, the realized loss on risk management contracts was $1.8 million, resulting from $1.4 million in premiums paid on oil price risk management contracts and $0.4 million negative cash settlement on foreign exchange risk management contracts. In the same period of 2023, the Company realized a gain on risk management contracts of $2.2 million, resulting from a gain on cash settlement of risk management contracts of foreign exchange currency of $4.1 million partially offset by $1.9 million in premiums paid on oil price risk management contracts.

During the nine months ended September 30, 2024, the realized loss on risk management contracts was $2.7 million, resulting from $8.7 million, in premiums paid on oil price risk management contracts, partially offset by a gain of $6.0 million, from the cash settlement of foreign exchange risk management contracts. In comparison, the realized gain on risk management contracts during the same period in 2023 was $5.4 million resulting from a gain on cash settlement of risk management contracts of foreign exchange currency of $4.1 million during the third quarter of 2023 and the unwinding of risk management contracts of foreign exchange currency of $9.0 million during the second quarter of 2023, partially offset by $7.7 million of premiums paid on oil price risk management contracts.

For the three and nine months ended September 30, 2024, risk management contracts had an unrealized gain of $7.6 million and a loss of $3.9 million, respectively, compared to a loss of $4.0 million and gain of $4.9 million, respectively, in the same periods of 2023, primarily from the reclassification of amounts to realized losses from instruments settled and variance 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 is designed to protect a minimum of 40% of the estimated production with a tactical approach, using derivative commodity instruments to protect the revenue generation and cash position of the Company, while maximizing the upside.

Type of Instrument	Term	Benchmark	Notional Amount / Volume in USD	Avg. Put / Call Par forward (COP$)	Carrying Amount Assets	Carrying Amount Liabilities
Put	October to November 2024	Brent	844,000	78	3,206	—
Total as at September 30, 2024			844,000		3,206	—

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

Type of Instrument	Term	Benchmark	Notional Amount / Volume (bbl)	Avg. Strike Prices Put $/bbl
Put spread	December 2024	Brent	500,000	66 / 75
Put	January 2025 to February 2025	Brent	739,000	70
		Total volume (bbl)	1,239,000	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. In addition, since the second and third quarter of 2024, the Company has entered into new derivatives in order to hedge the currency risk exposure for the collection of the dividends from ODL as required by the PIL Loan Facility and for the payments related to the third disbursement of the PIL Loan Facility (as defined below).

As of September 30, 2024, the Company has the following foreign currency derivatives contracts:

				Avg. Put / Call	Carrying Amount	
Type of Instrument	Term	Benchmark	Notional Amount / Volume in USD	Par forward (COP$)	Assets	Liabilities
Zero-cost collars	October to December 2024	USD / COP	60,000,000	4,100/4,476	193	—
Zero-cost collars	January to March 2025	USD / COP	60,000,000	4,150/4,618	620	—
Forward	October 2024	USD / COP	17,099,200	4,386.17	781	—
Forward [1]	October to December 2024	USD / COP	17,851,713	4,078/4,115	574	—
Forward	February 2025	USD / COP	7,000,000	4,302.55	72	—
Total as at September 30, 2024					2,240	—

[1] *Contracts related to the PIL Loan Facility (as defined below).*

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

					Avg. Strike Prices
Type of Instrument	Term	Benchmark	Currency Hedged	Notional Amount / Volume in USD	Par forward (COP$)
Zero-cost collars	April 2025 to June 2025	USD / COP	USD	60,000,000	4,200/4,626
Zero-cost collars	July 2025 to September 2025	USD / COP	USD	60,000,000	4,200/4,795
		Total		120,000,000	

Income Tax Expense

	Three months ended September 30		Nine months ended September 30	
($M)	2024	2023	2024	2023
Current income tax expense	(6,792)	(15,333)	(13,075)	(27,141)
Deferred income tax expense	(3,668)	(17,679)	(56,629)	(15,996)
Total income tax expense	(10,460)	(33,012)	(69,704)	(43,137)

For the three and nine months ended September 30, 2024, the Company recognized a current income tax expense of $6.8 million and $13.1 million, respectively, compared to $15.3 million and $27.1 million, respectively, in the same periods of 2023, and a deferred income tax expense of $3.7 million and $56.6 million, respectively, compared to $17.7 million and $16.0 million, respectively, in the same periods of 2023.

The decrease in the current income tax expense is mainly due to a reduction in net income before income tax and taxable net income and in the nominal income rate from 50% to 45%. The increase in the deferred tax expense for the nine months ended September 30, 2024, is mainly due to foreign exchange rate fluctuations.

CRA 2016 Settlement

The Company entered into Minutes of Settlement dated July 12, 2024, with the Canadian Minister of National Revenue to resolve a dispute in connection with the Company's 2016 restructuring process and relating to, among other things, the fair market value of the Company's Common Shares as at November 2, 2016, the computation of the net capital losses and the computation of non-capital losses of the Company in respect of its taxation year ending December 31, 2016 (the "**CRA Settlement**").

The Company has assessed the impact of the CRA Settlement on the computation of the historical paid-up capital in respect of the Common Shares. This assessment has resulted in a decrease in the net capital losses of the Company, as last reported in the 2023 Annual Financial Statements, and an increase in the computed amount of the historical paid-up capital in respect of the Common Shares. The resulting increase in the computed amount of the historical paid-up capital in respect of the Common Shares may reduce the amount of the dividends deemed to have been received by certain shareholders in connection with the repurchase of Common Shares under the Company's substantial issuer bid, completed on August 11, 2022.

Net Income

($M)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Net income [(1)]	16,588	32,582	5,239	101,459
Per share – basic ($)	0.20	0.38	0.06	1.19
Per share – diluted ($)	0.19	0.37	0.06	1.16

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

During the third quarter of 2024, the Company reported a net income, attributable to equity holders of the Company, of $16.6 million, which included income from operations $26.8 million, $13.4 million from share of income from associates, and $5.8 million related to income on risk management contracts, partially offset by finance expenses of $17.7 million and an income tax expense of $10.5 million (including $3.7 million of deferred income tax expenses). This compared to net income, attributable to equity holders of the Company, of $32.6 million for the third quarter of 2023, which included operating income of $65.0 million, $13.7 million of share of income from associates, foreign exchange gain of $4.3 million and finance income of $1.9 million, partially offset by finance expenses of $16.4 million, other expenses of $1.2 million and income tax expenses of $33.0 million.

For the nine months ended September 30, 2024, the Company reported a net income, attributable to equity holders of the Company, of $5.2 million, which included operating income of $101.7 million and $40.7 million from share of income from associates, partially offset by income tax expense of $69.7 million (including $56.6 million of deferred income tax expenses), finance expenses of $52.4 million, $9.2 million of foreign exchange losses and $6.6 million related to loss on risk management contracts. This compared to a net income, attributable to equity holders of the Company, of $101.5 million, which included operating income of $117.8 million, $41.6 million of share of income from associates, gain on risk management contracts by $10.2 million and foreign exchange gain of $9.6 million, partially offset by finance expenses of $47.3 million and income tax expenses of $43.1 million.

Capital Expenditures and Acquisitions

($M)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Development drilling	29,957	28,471	102,863	99,176
Development facilities [(1)]	23,772	22,918	69,016	59,468
Colombia and Ecuador exploration	7,626	8,435	21,036	32,253
Other	6,641	3,195	14,496	7,133
Total Colombia and Ecuador upstream capital expenditures	**67,996**	**63,019**	**207,411**	**198,030**
Colombia infrastructure	13,860	2,939	21,883	5,572
Guyana exploration	555	8,172	2,696	156,840
Total capital expenditures [(2)]	**82,411**	**74,130**	**231,990**	**360,442**

[(1)] Investments related to the replacement and repairs of the affected assets in the Quifa Block due to the trunkline unexpected failures are not included.
[(2)] Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24.

Capital expenditures for the three and nine months ended September 30, 2024, were $82.4 million and $232.0 million, respectively, compared with $74.1 million and $360.4 million, respectively, in the same periods of 2023, as follows:

Development drilling. During the three and nine months ended September 30, 2024, development drilling expenditures were $30.0 million and $102.9 million, respectively, compared to $28.5 million and $99.2 million, respectively, in the same periods of 2023. During the third quarter of 2024, 15 development wells were drilled in the CPE6, Quifa and Sabanero blocks, while 14 development wells were drilled in the same period of 2023 in the Quifa and CPE-6 Blocks and one injector well was drilled at the CPE-6 Block. During the nine months ended September 30, 2024, 63 development wells were drilled in the Quifa, CPE-6 and Sabanero blocks, in Colombia, and 3 development wells were drilled in the Perico Block, in Ecuador, while in the same period of 2023 a total of 52 development wells, including 2 injector wells, were drilled in the Quifa, CPE-6 and Cubiro blocks.

Development facilities. During the three and nine months ended September 30, 2024, development facilities expenditures were $23.8 million and $69.0 million, respectively, mainly related to the expansion of the development facilities increasing water-handling capacity at the CPE-6 Block to 300 Mbwpd, on track to increase to up to 360 Mbwpd by year-end; new and improved flow lines in the Quifa Block supporting new well production and the SAARA connection; the expansion of the Sabanero Block facilities; and the purchase of facilities in the Perico Block. For the same periods of 2023, development facilities expenditures were $22.9 million and $59.5 million, respectively, mainly related to the expansion of the development facilities in the CPE-6 Block increasing water-handling capacity to 180 Mbwpd and new flow lines in the Quifa Block, particularly for the SAARA project.

Colombia and Ecuador Exploration. During the three and nine months ended September 30, 2024, expenditures related to exploration activities were $7.6 million and $21.0 million, respectively, compared $8.4 million and $32.3 million, respectively, in the same periods of 2023. During the three months ended September 30, 2024, the exploration activities executed included one exploration well drilled in Ecuador. Predrilling activities, related to socialization, are also ongoing for two exploration wells in Colombia. Details regarding exploration activities in Colombia and Ecuador are as follows:

Colombia. The Company's exploration focus remains on the Lower Magdalena Valley and Llanos Basins in Colombia during the third quarter of 2024. At the VIM-1 Block, all pre-drill activities related to civil work for the platform and roads were completed for the Hidra-1 exploration well, while the well is drill-ready, social-related issues have resulted in the decision to pause the spud of the well to 2025. Pre-drilling activities for two new exploration wells in the Cachicamo Block were sanctioned, the first well, Papilio-1 expected to spud in December 2024 and the second well, Greta Norte-1 in January 2025. 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. During the third quarter of 2024, at the Espejo Block (Frontera holds a 50% W.I. and is a non-operator), the Espejo Norte-A1 well (formerly known as Espejo Centro-1) was drilled, reaching a total depth of 9,912 feet MD, targeting the Napo formation. After a few weeks of testing producing approximately 100 bopd gross the well was deemed non-economic and is currently under evaluation. In addition at the Espejo Sur-B3 exploration well, drilled during the second quarter of 2024, a long-term test is undergoing with a production of 500 bbl/d gross and a BSW of 72%. Espejo Block currently is producing average 670 bbl/d gross, the development plan will be assessed during the fourth quarter 2024.

Other. Other capital expenditures for the three and nine months ended September 30, 2024, were $6.6 million and $14.5 million, respectively. The expenditures 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 nine months ended September 30, 2024, was $13.9 million and $21.9 million, respectively, mostly for Puerto Bahia investments, including: (i) the Reficar Connection Project, including engineering and civil works, expenses related to rights of way, among others, (ii) tank maintenance, and (iii) general cargo terminal equipment and facilities; and the SAARA project. During the same periods of 2023, capital expenditures were $2.9 million and $5.6 million, respectively, for the SAARA project and Puerto Bahia.

Guyana exploration. During the three and nine months ended September 30, 2024, Guyana exploration expenditures were $0.6 million and $2.7 million, respectively, mainly related to post-well studies and other capitalized expenses, compared to $8.2 million and $156.8 million, respectively, during the same periods of 2023, which were related to Wei-1 exploration well.

Selected Quarterly Information

Operational and financial results		2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4
Heavy crude oil production	(bbl/d)	25,312	24,839	23,398	23,002	24,097	24,051	22,270	22,144
Light and medium crude oil combined production	(bbl/d)	12,794	12,583	12,580	13,795	13,964	15,188	16,518	17,073
Total crude oil production	(bbl/d)	38,106	37,422	35,978	36,797	38,061	39,239	38,788	39,217
Conventional natural gas production	(mcf/d)	3,192	4,019	3,283	4,760	5,250	5,626	8,590	9,097
Natural gas liquids production	(boe/d)	1,950	1,785	1,639	1,635	1,820	1,823	1,291	993
Total production	(boe/d)	40,616	39,912	38,193	39,267	40,802	42,049	41,586	41,806
Sales volumes, net of purchases	(boe/d)	34,192	31,523	30,185	34,449	35,289	35,799	30,424	34,323
Brent price reference	($/bbl)	78.71	85.03	81.76	82.85	85.92	77.73	82.10	88.63
Oil and gas sales, net of purchases (1)	($/boe)	68.06	76.18	73.71	75.76	78.48	67.91	69.07	82.60
Premiums paid on oil price risk management contracts (2)	($/boe)	(0.45)	(1.32)	(1.27)	(0.69)	(0.59)	(0.80)	(1.16)	(1.32)
Royalties (2)	($/boe)	(0.91)	(2.01)	(1.64)	(1.79)	(3.76)	(3.02)	(3.36)	(6.04)
Net sales realized price (1)	($/boe)	66.70	72.85	70.80	73.28	74.13	64.09	64.55	75.24
Production costs (excluding energy cost), net of realized FX hedge impact (2)	($/boe)	(8.88)	(10.79)	(10.21)	(9.69)	(8.82)	(8.45)	(8.12)	(8.48)
Energy costs, net of realized FX hedge impact (2)	($/boe)	(5.11)	(4.74)	(5.29)	(5.06)	(5.04)	(3.94)	(3.95)	(3.08)
Transportation costs, net of realized FX hedge impact(2)	($/boe)	(12.12)	(10.92)	(11.33)	(11.02)	(11.73)	(10.89)	(11.20)	(10.55)
Operating netback per boe (1)	($/boe)	40.59	46.40	43.97	47.51	48.54	40.81	41.28	53.13
Revenue	($M)	278,475	279,523	265,175	299,501	308,867	289,869	250,366	317,568
Net income (loss) (3)	($M)	16,588	(2,846)	(8,503)	92,038	32,582	80,207	(11,330)	197,796
Per share – basic ($)	($)	0.20	(0.03)	(0.10)	1.08	0.38	0.94	(0.13)	2.29
Per share – diluted ($)	($)	0.19	(0.03)	(0.10)	1.04	0.37	0.92	(0.13)	2.25
General and administrative	($M)	12,719	12,928	13,556	16,891	11,925	12,422	12,669	12,761
Operating EBITDA (4)	($M)	103,184	110,321	97,248	121,036	137,800	116,461	91,922	144,994
Capital expenditures (4)	($M)	82,411	80,198	69,381	82,292	74,130	154,860	131,452	134,165

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24.
(3) Refers to net income (loss) attributable to equity holders of the Company.
(4) 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, movement in Brent benchmark prices, timing of cargo shipments, and fluctuations in crude oil price differentials. Since the second quarter of 2023 until the first quarter of 2024, production decreased mainly due to: (i) natural decline and well failures in light and medium crude oil combined, and conventional natural gas, (ii) the return of the Neiva Block following the completion of the production contract, and (iii) the relinquishment of the La Creciente Block. However, in the past two quarters, production has increased mainly due to: (i) successful drilling campaign in and investment in water-handling facilities in the Quifa and CPE-6 blocks, (ii) development of facilities in the VIM-I Block, and (iii) the development of the Perico Block in Ecuador. During the last year, transportation costs had increased, mainly due to the regular annual increase of transportation tariffs. Energy costs increased primarily as a result of an El Niño-related increase in market prices. In addition, production costs (excluding energy cost) have also fluctuated mainly due to the inflationary pressures on services, wages indexation, well services and maintenance activities, and changes in barrels produced affecting variable costs.

Trends in the Company's net income (loss), attributable to equity holders of the Company, are also impacted most significantly by the recognition and derecognition of deferred income taxes and expenses or reversal of impairment of oil and gas and exploration and evaluation assets, DD&A, foreign exchange gain or losses and gain or losses from risk management contracts that 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, 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	99.97% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	100% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [2]
SAARA [3]	Reverse osmosis water treatment, name plate capacity of 1,000,000 bwpd	100% interest in Agro Cascada	Consolidation
ProAgrollanos	Palm oil plantation, 20,000-27,000 tons per year of fresh fruit bunch	100% interest in Promotora Agricola de los Llanos	Consolidation

(1) Interests include both direct and indirect interests.
(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.

Performance Highlights

					Nine months ended September 30	
		Q3 2024	Q2 2024	Q3 2023	2024	2023
Operational and IFRS Results						
Volumes pumped at oil pipeline facility	(bbl/d)	243,997	249,196	251,988	246,403	240,519
Volumes throughput at port liquids facility	(bbl/d)	46,964	61,798	53,586	54,015	63,400
Volumes RORO at port general cargo facility	(Units)	20,914	18,986	25,346	52,749	85,645
Volumes at port Break Bulk Volumes	(Tons/m3)	15,067	11,256	43,534	34,804	59,350
Volumes of water received from production fields	(bwpd)	49,589	14,467	87,796	32,505	51,398
Production of fresh fruit bunch	(Tons)	5,184	8,895	4,325	19,174	17,568
Infrastructure Colombia segment income	($M)	13,122	14,620	13,952	40,294	45,380
Infrastructure Colombia segment cash flow from operating activities	($M)	12,679	29,922	15,291	43,246	38,336
Non IFRS Results [1]						
Adjusted Infrastructure Revenues	($M)	42,152	43,055	43,759	126,114	126,298
Adjusted Infrastructure EBITDA	($M)	26,181	27,823	26,858	79,691	82,733
Adjusted Infrastructure Cash	($M)	75,625	48,831	57,159	75,625	57,159
Adjusted Infrastructure Debt	($M)	123,902	113,763	123,778	123,902	123,778
Capital Expenditures Infrastructure Colombia Segment	($M)	13,860	3,467	2,939	21,883	5,572

(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.

Infrastructure Colombia Segment Results

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

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	11,247	13,068	34,669	38,416
Costs	(7,592)	(9,347)	(23,339)	(24,498)
General and administrative expenses	(1,528)	(1,477)	(4,396)	(4,472)
Depletion, depreciation and amortization	(1,921)	(1,720)	(5,699)	(4,608)
Impairment	(355)	—	(355)	—
Restructuring, severance and other costs	(140)	(298)	(1,298)	(1,101)
Infrastructure (loss) income from operations	**(289)**	**226**	**(418)**	**3,737**
Share of Income from associates - ODL	13,411	13,726	40,712	41,643
Infrastructure Colombia segment income	**13,122**	**13,952**	**40,294**	**45,380**
Infrastructure Colombia segment cash flow from operating activities	12,679	15,291	43,246	38,336
Capital Expenditures Infrastructure Colombia Segment [1]	13,860	2,939	21,883	5,572

[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.

The Company's Infrastructure Colombia Segment income for the three and nine months ended September 30, 2024, decreased $0.8 million and $5.1 million, respectively, compared to the same period of 2023, mainly due to lower revenue from Puerto Bahia and a reduced share of Income from ODL.

Segment capital expenditures for the three and nine months ended September 30, 2024, were $13.9 million and $21.9 million, respectively, mostly for Puerto Bahia investments, including: (i) the Reficar Connection Project, including engineering and civil works, expenses related to rights of way, among others, (ii) tank maintenance, and (iii) general cargo terminal equipment and facilities; and the SAARA project. During the same periods of 2023, capital expenditures were $2.9 million and $5.6 million, respectively, for the SAARA project and Puerto Bahia.

ODL Pipeline

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

For the three and nine months ended September 30, 2024, ODL generated an EBITDA of $68.7 million and $207.9 million, respectively, and $38.3 million and $116.3 million, respectively, of net income. 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 from the 100% ODL is as follows:

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Revenue	88,301	87,689	261,272	251,093
FEC revenue (billed units)	7,061	7,960	22,035	22,749
Third party revenues	81,240	79,729	239,237	228,344
Costs	(13,782)	(12,749)	(37,750)	(30,457)
General administrative expenses	(5,792)	(4,615)	(15,643)	(11,243)
Depletion, depreciation and amortization	(8,152)	(8,083)	(24,011)	(20,714)
Other non-operating expense	(1,626)	(1,911)	(4,913)	(5,631)
Income tax	(20,632)	(21,113)	(62,634)	(64,067)
ODL Net Income	**38,317**	**39,218**	**116,321**	**118,981**

($M)	**September 30 2024**	**December 31 2023**
ODL debt	39,789	45,147
ODL cash and cash equivalents	77,174	131,839

The following table shows the volumes pumped per injection point:

(bbl/d)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
At Rubiales Station	172,745	179,310	170,769	168,290
At Jagüey and Palmeras Stations	71,252	72,678	75,634	72,229
Total	**243,997**	**251,988**	**246,403**	**240,519**

The following table shows the volumes received per block:

(bbl/d)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Rubiales	106,821	110,558	103,529	108,071
Quifa	28,521	29,725	28,939	29,681
CPE-6	1,508	2,248	2,709	2,156
Other blocks	90,857	95,800	96,175	84,958
Total	**227,707**	**238,331**	**231,352**	**224,866**

For the three and nine months ended September 30, 2024, the Company recognized $13.4 million and $40.7 million, respectively, as its share of income from ODL, which was lower than the same periods of 2023 by $0.3 million and $0.9 million respectively. This result was primarily due to an increase in operating and G&A expenses resulting from COP variance, inflationary pressures on services and wages indexation, and for the nine months ended September 30, 2024, partially offset by the increase in crude oil volumes received and transported from the Caño Sur and Llanos 34 blocks. Additionally, the ODL has increased its pipeline transportation tariffs by 7.8% since September 2024.

During the three and nine months ended September 30, 2024, ODL declared net dividends to PIL of $Nil and $54.9 million, respectively (2023: $Nil and $37.0 million, respectively), and a return of capital of $Nil and $7.9 million, respectively (2023: $Nil and $5.2 million, respectively). During the three and nine months ended September 30, 2024, PIL received cash of $12.2 million and $43.5 million, respectively, in dividends and return of capital from ODL (2023: $11.7 million and $37.5 million, respectively).

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 multipurpose 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 with a nominal capacity of 2,672,000 barrels, and RORO and breakbulk services in the general cargo terminal.

($M)	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Revenue	9,712	12,334	30,660	35,353
Liquids port facility	6,577	7,838	21,699	23,284
FEC liquids port facility	1,800	2,093	5,820	5,660
Third party liquids port facility	4,777	5,745	15,879	17,624
General cargo	3,135	4,496	8,961	12,069
Costs	(4,797)	(6,420)	(16,470)	(17,270)
General and administrative expenses	(1,363)	(1,400)	(4,037)	(4,196)
Depletion, depreciation and amortization	(1,743)	(1,442)	(5,147)	(3,993)
Impairment	(355)	—	(355)	—
Restructuring, severance and other costs	(140)	(298)	(1,298)	(1,101)
Puerto Bahia Operating Income	1,314	2,774	3,353	8,793

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

(bbl/d)	Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
FEC volumes	12,459	13,789	14,147	13,163
Third party volumes	34,505	39,797	39,868	50,238
Total	**46,964**	**53,586**	**54,015**	**63,401**

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

		Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
RORO	units [(1)]	20,914	25,346	52,749	85,645
	dwell time in days [(2)]	47	51	48	46
Break Bulk Volumes	Tons/m3 [(3)]	15,067	43,534	34,804	59,350

[(1)] Carry wheeled cargo, mainly corresponds to 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, thereby eliminating the necessity for storage, as occurred during third quarter of 2024.

[(3)] Other types of cargo different from wheeled cargo.

For the three and nine months ended September 30, 2024, Puerto Bahia had an operating income of $1.3 million and $3.4 million, respectively, (2023: $2.8 million and $8.8 million, respectively). The reduction is mainly due to lower volumes handled at the liquids terminal as a result of lower the navigability levels in the Magdalena River due to weather conditions, and lower volumes in general cargo of RORO and break bulk, compared to the same periods of 2023. The liquids terminal volumes impacted by these severe weather conditions during the third quarter of 2024 were estimated at approximately 10,900 bbl/d, which would have represented an additional $1.0 million in the revenues. Puerto Bahia expects conditions to improve and for volumes to recover in the fourth quarter 2024. This reduction in the operating income was partially offset by a tariff increase in RORO and a costs reduction of 25% and 5%, respectively, primarily resulting from the end of the port operation outsourcing contract.

During the third quarter of 2023, Puerto Bahia and Reficar agreed to connect Puerto Bahia's port facility and the Cartagena refinery with a 6.8-kilometre, 18-inch, bi-directional hydrocarbon flow line. This connection will facilitate the continuous transport of crude oil and other hydrocarbons between the two locations and shall have a capacity of 84,000 barrels per day; capable of handling both, imported and domestically produced crude oil. As of the third quarter 2024, the connection continues advancing with an investment of $9.8 million and is currently over 60% complete, and the Company expects that the connection shall become operational by the end of the year.

On July 22, 2024, Frontera announced that its subsidiary, Puerto Bahia and GASCO had entered into a Framework Collaboration Agreement to jointly pursue a LPG project at the Puerto Bahia port, and currently working groups have been assembled and detailed engineering work is taking place. The estimated cost of the project is expected to range between $50 and $60 million, which will be shared between Puerto Bahia and GASCO. Puerto Bahia's contributions are expected to be largely in-kind and the project is expected to be commissioned by 2027.

Water Treatment Facility and Palm Oil Plantation

In 2021, Frontera launched a feasibility analysis of the agricultural water reuse utilization system, SAARA, consisting of a reverse osmosis plant water treatment facility (built in 2016) that the Company began recommissioning in 2023. The plant will help solve and take advantage of the availability of production water from the Quifa and Rubiales blocks. The plant was designed to remove salts from the treated water to bring it to a state suitable for use in agricultural irrigation for industrial crops.

Through its wholly-owned subsidiary ProAgrollanos, the Company operates an oil palm business located in the Municipality of Puerto Gaitan, department of Meta, Colombia. Spanning across approximately 2,960 hectares currently planted, its oil palm plantation yielded 22,823 tons of fresh fruit bunches in the last twelve months. These crops typically exhibit an estimated productive lifespan of 30 years.

A portion of the water treated by SAARA is irrigated and reused in ProAgrollanos' agricultural activities, increasing the irrigation and targeting improving palm crop productivity within the next 24 months. During the recommissioning period in 2023, SAARA processed approximately 20.6 million barrels of water, irrigating approximately 400 hectares of palm oil crops in ProAgrollanos.

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

($M)	Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
Revenue	1,535	734	4,009	3,063
Fresh fruit bunch from palm oil	896	734	3,170	3,063
SAARA	639	—	839	—
Costs	(2,795)	(2,927)	(6,869)	(7,228)
Fresh fruit bunch from palm oil	(1,105)	(886)	(2,864)	(2,354)
SAARA	(1,690)	(2,041)	(4,005)	(4,874)
General and administrative expenses	(165)	(77)	(359)	(276)
Depletion, depreciation and amortization	(178)	(278)	(552)	(615)
SAARA and Palm Oil Assets Operating Loss	**(1,603)**	**(2,548)**	**(3,771)**	**(5,056)**

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

($M)		Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
Fresh fruit bunch from palm oil (produced - sold)	(Tons)	5,184	4,325	19,174	17,568
Production per hectare per year [1]	(Tons/ha/year)	7.71	7.49	—	—
Palm oil fruit price	($/Ton)	172	159	166	165
Volumes of water received from production fields	(bwpd)	49,589	87,796	32,505	51,398
Volumes of water irrigated in palm oil cultivation	(bwpd)	44,585	64,797	27,594	38,449

[1] Tons per hectare per year are calculated using the total production for the last twelve months ended September 30, 2024.

For the three and nine months ended September 30, 2024, sales from fresh fruit bunches of oil palm was $0.9 million and $3.2 million, respectively, an increase of $0.2 million and $0.1 million, respectively, compared to the same periods of 2023, resulting primarily from an increase in field productivity and market prices. Fluctuation in fruit production volume is attributed to factors including climate conditions, agricultural practices (i.e. fertilization), workforce availability, changes in the administration operation model and community blockades in the area near to the crop.

During the three and nine months ended September 30, 2024, the volumes of water received and irrigated for palm oil plantations were lower compared to the same periods in 2023, mainly due to the temporary suspension of the operation of the plant following the conclusion of the project's pilot program on January 31, 2024, subsequently reactivated in June 2024 after the signature of the agreement with Ecopetrol to start the first phase of the SAARA project. For the three months ended September 30, 2024 the project processed 49,589 barrels of water per day generating a revenue of $0.6 million.

The Company is investing to increase the processing capacity of SAARA to 250,000 barrels of water per day by year end and has executed investment by $6.1 million during the year ended September 30, 2024.

Subsequent to the third quarter, on October 10, 2024, Agro Cascada, a wholly owned subsidiary of the Company, borrowed COP$29,330 million (roughly $7 million) from Citibank Colombia under a 1-year facility to support the development of the Company's water treatment facilities. Frontera Energy Colombia Corp. Sucursal Colombia acted as a guarantor of the loan.

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 our 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 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, payments of minimum work commitments and, certain non-cash items (such as impairments, foreign exchange, unrealized risk management contracts, and share-based compensation) 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 income to Operating EBITDA:

	Three months ended September 30		Nine months ended September 30	
($M)	**2024**	**2023**	**2024**	**2023**
Net income [1]	16,588	32,582	5,239	101,459
Finance income	(3,126)	(1,941)	(6,534)	(7,714)
Finance expenses	17,696	16,411	52,395	47,320
Income tax expense	10,460	33,012	69,704	43,137
Depletion, depreciation and amortization	68,269	61,756	197,269	209,858
Expense (recovery) of asset retirement obligation	5,546	3,480	4,549	(24,001)
Expenses of impairment	361	2,342	1,780	23,819
Trunkline costs	3,829	—	3,829	—
Post-termination obligation	(314)	1,377	(128)	7,654
Share-based compensation	(149)	305	891	841
Restructuring, severance and other costs	361	1,407	3,216	4,804
Share of income from associates	(13,411)	(13,726)	(40,712)	(41,643)
Foreign exchange loss (gain)	631	(4,305)	9,246	(9,551)
Other loss (income)	4,292	1,207	7,425	(4,382)
Unrealized (gain) loss on risk management contracts	(7,644)	4,002	3,941	(4,880)
Realized loss on risk management contract for ODL dividends received	288	—	288	—
Non-controlling interests	(201)	(109)	(644)	(538)
Gain on repurchased 2028 Unsecured Notes	(292)	—	(1,001)	—
Operating EBITDA	**103,184**	**137,800**	**310,753**	**346,183**

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

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 September 30		Nine months ended September 30	
	2024	2023	2024	2023
Consolidated Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	84,533	61,745	234,415	170,891
Additions to exploration and evaluation assets	7,496	12,169	20,450	190,039
Total additions in Consolidated Statements of Cash Flows	**92,029**	**73,914**	**254,865**	**360,930**
Non-cash adjustments [1]	(7,137)	216	(20,394)	(488)
Cash adjustments [2]	(2,481)	—	(2,481)	—
Total Capital Expenditures	**82,411**	**74,130**	**231,990**	**360,442**
Capital Expenditures attributable to Infrastructure Colombia Segment	13,860	2,939	21,883	5,572
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	68,551	71,191	210,107	354,870
Total Capital Expenditure	**82,411**	**74,130**	**231,990**	**360,442**

(1) Related to material consumption movements, capitalized non-cash items and other adjustments.
(2) Investments related to the replacement and repairs of the affected assets in the Quifa Block due to unexpected failures in a trunkline..

Adjusted Infrastructure Colombia Calculations

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

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

	Three months ended September 30		Nine months ended September 30	
($M) [1]	**2024**	**2023**	**2024**	**2023**
Revenue Infrastructure Colombia Segment	11,247	13,068	34,669	38,416
Revenue from ODL	88,301	87,689	261,272	251,093
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	30,905	30,691	91,445	87,882
Adjusted Infrastructure Revenues	**42,152**	**43,759**	**126,114**	**126,298**
Operating cost Infrastructure Colombia Segment	(7,592)	(9,347)	(23,339)	(24,498)
Operating Cost from ODL	(13,782)	(12,749)	(37,750)	(30,457)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	(4,824)	(4,462)	(13,213)	(10,660)
Adjusted Infrastructure Operating Costs	**(12,416)**	**(13,809)**	**(36,552)**	**(35,158)**
General and administrative Infrastructure Colombia Segment	(1,528)	(1,477)	(4,396)	(4,472)
General and administrative from ODL	(5,792)	(4,615)	(15,643)	(11,243)
Direct participation interest in the ODL	35 %	35 %	35 %	35 %
Equity adjustment participation of ODL [1]	(2,027)	(1,615)	(5,475)	(3,935)
Adjusted Infrastructure General and Administrative	**(3,555)**	**(3,092)**	**(9,871)**	**(8,407)**

(1) Revenues and expenses related to the ODL are accounted for using the equity method described in the 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]	September 30 2024	December 31 2023
Cash and cash equivalents - unrestricted	205,572	159,673
Cash and cash equivalents of Non-Infrastructure Colombia Segment's	(156,958)	(134,186)
Total Cash Infrastructure Colombia Segment	48,614	25,487
Cash and cash equivalent from ODL	77,174	131,839
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	27,011	46,144
Adjusted Infrastructure Cash	**75,625**	**71,631**
Short-Term and Long-Term Debt	517,199	517,604
Debt of Non-Infrastructure Colombia Segment's	(407,223)	(421,982)
Total Debt	109,976	95,622
Debt from ODL	39,789	45,147
Direct participating interest in the ODL	35 %	35 %
Equity adjustment participation of ODL [1]	13,926	15,801
Adjusted Infrastructure Debt	**123,902**	**111,423**

[1] 35% ODL participation is accounted using the equity method in the 2023 Annual Consolidated Financial Statements, Cash and cash equivalents, and Debt related to the ODL are embedded in the value of the Investment in Associates.

Adjusted Infrastructure EBITDA

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

	Three months ended September 30		Nine months ended September 30	
($M)	2024	2023	2024	2023
Adjusted Infrastructure Revenue	42,152	43,759	126,114	126,298
Adjusted Infrastructure Operating Costs	(12,416)	(13,809)	(36,552)	(35,158)
Adjusted Infrastructure General and Administrative	(3,555)	(3,092)	(9,871)	(8,407)
Adjusted Infrastructure EBITDA	**26,181**	**26,858**	**79,691**	**82,733**

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 September 30		Nine months ended September 30	
	2024	2023	2024	2023
Produced crude oil and products sales ($M)[1]	223,678	260,828	657,367	685,842
Purchased crude net margin ($M)	(9,594)	(6,023)	(22,286)	(20,699)
Oil and gas sales, net of purchases ($M)	**214,084**	**254,805**	**635,081**	**665,143**
Sales volumes, net of purchases - (boe)	3,145,664	3,246,588	8,760,876	9,242,415
Produced crude oil and gas sales ($/boe)	71.11	80.34	75.03	74.21
Oil and gas sales, net of purchases ($/boe)	68.06	78.48	72.49	71.97

(1) Excludes sales from port services as they are not part of the oil and gas segment. For further information, refer to the “Infrastructure Colombia” section on page 19.

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 September 30		Nine months ended September 30	
	2024	2023	2024	2023
Oil and gas sales, net of purchases ($M) [1]	214,084	254,805	635,081	665,143
Crude oil sales volumes, net of purchases - (bbl)	3,095,926	3,147,019	8,594,613	8,923,612
Conventional natural gas sales volumes - (mcf)	283,837	567,754	948,850	1,817,714
Realized oil price, net of purchases ($/bbl)	68.53	80.08	73.20	73.49
Realized conventional natural gas price ($/mcf)	6.77	4.91	6.27	5.17

(1) Non-IFRS financial measure.

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 September 30		Nine months ended September 30	
	2024	2023	2024	2023
Oil and gas sales, net of purchases ($M) [1]	214,084	254,805	635,081	665,143
(-) Premiums paid on oil price risk management contracts ($M)	(1,425)	(1,930)	(8,710)	(7,705)
(-) Royalties ($M)	(2,853)	(12,216)	(13,133)	(31,266)
Net sales ($M)	**209,806**	**240,659**	**613,238**	**626,172**
Sales volumes, net of purchases - (boe)	3,145,664	3,246,588	8,760,876	9,242,415
Oil and gas sales, net of purchases ($/boe)	68.06	78.48	72.49	71.97
Premiums paid on oil price risk management contracts [2]	(0.45)	(0.59)	(0.99)	(0.83)
Royalties ($/boe) [2]	(0.91)	(3.76)	(1.50)	(3.38)
Net sales realized price ($/boe)	**66.70**	**74.13**	**70.00**	**67.76**

(1) Non-IFRS financial measure.
(2) 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 September 30		Nine months ended September 30	
	2024	2023	2024	2023
Purchased crude oil and products sales ($M)	47,963	48,532	148,283	159,745
(-) Cost of diluent and oil purchased ($M) (1)	(57,557)	(54,555)	(170,569)	(180,444)
Purchased crude net margin ($M)	**(9,594)**	**(6,023)**	**(22,286)**	**(20,699)**
Sales volumes, net of purchases - (boe)	3,145,664	3,246,588	8,760,876	9,242,415
Purchased crude net margin ($/boe)	**(3.05)**	**(1.86)**	**(2.54)**	**(2.24)**

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

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

Production costs (excluding energy cost), 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 cost), net of realized FX hedge impact divided by production (before royalties).

A reconciliation of this calculation is provided below:

	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Production costs (excluding energy cost) ($M)	32,395	35,237	110,635	102,795
(-) Realized loss (gain) on FX hedge attributable to production costs (excluding energy cost) ($M) (1)	182	(2,134)	(3,358)	(6,974)
SAARA inter-segment costs	587	—	587	—
Production costs (excluding energy cost), net of realized FX hedge impact ($M) (2)	33,164	33,103	107,864	95,821
Production (boe)	3,736,672	3,753,784	10,844,372	11,323,221
Production costs (excluding energy cost), net of realized FX hedge impact ($/boe)	8.88	8.82	9.95	8.46

(1) See “Gain (Loss) on Risk Management Contracts” on page 14.

(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 cost, net of realized FX hedge impact per boe is a non-IFRS ratio that is calculated using energy cost, net of realized FX hedge impact divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended September 30		Nine months ended September 30	
	2024	2023	2024	2023
Energy costs ($M)	19,019	19,705	55,984	50,919
(-) Realized loss (gain) on FX hedge attributable to energy costs ($M) (1)	84	(793)	(1,267)	(2,162)
Energy costs, net of realized FX hedge impact ($M) (2)	19,103	18,912	54,717	48,757
Production (boe)	3,736,672	3,753,784	10,844,372	11,323,221
Energy costs, net of realized FX hedge impact ($/boe)	5.11	5.04	5.05	4.31

(1) See “(Loss) Gain on Risk Management Contracts” on page 14.

(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 September 30		Nine months ended September 30	
	2024	2023	2024	2023
Transportation costs ($M)	39,273	40,166	109,385	116,666
(-) Realized loss (gain) on FX hedge attributable to transportation costs ($M) [1]	61	(744)	(982)	(2,511)
Transportation costs, net of realized FX hedge impact ($M) [2]	39,334	39,422	108,403	114,155
Net production (boe)	3,244,564	3,359,472	9,455,192	10,126,662
Transportation costs, net of realized FX hedge impact ($/boe)	12.12	11.73	11.46	11.27

(1) See "(Loss) Gain on Risk Management Contracts" on page 14.
(2) Non-IFRS financial measure.

Supplementary Financial Measures

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

Realized (loss) gain 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 (loss) gain on oil risk management contracts per boe is a supplementary financial measure that is calculated using Realized (loss) gain 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) is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under the 2023 NCIB (as defined below) during the period. 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, is comprised by the cash and cash equivalents and the 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, 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 relating to operations, commitments and existing contingencies;
- debt service requirements relating 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 using 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 will be sufficient to meet operational needs and other obligations.

As of September 30, 2024, the Company had a total cash balance of $240.3 million (including $34.8 million in restricted cash), which is $50.4 million higher than December 31, 2023.

For the nine months ended September 30, 2024, the Company generated $339.5 million, of cash from operations, including approximately $53.7 million of net income tax reimbursed (including $90 million in tax refund proceeds associated to the 2023 income tax return), which was used to fund cash outflows of $242.1 million for capital expenditures and other investing activities. For the nine months ended September 30, 2024, financing activities generated net outflows of $43.8 million, mainly as a result of $23.7 million of interest paid and other charges, $13.9 million used for the repayment in full of the principal amount outstanding of the PetroSud Debt, and the PIL Loan Facility (as defined below), $7.8 million in Common Shares purchased under the 2023 NCIB (as defined below), $7.8 million related to dividends paid to equity holders, $4.0 million in repurchases of the 2028 Unsecured Notes and $4.9 million in lease payments, partially offset by the disbursement of $18.8 million in net proceeds from the accordion tranche as part of the PIL Loan Facility (as defined below). In addition, the Company's net working capital(1) improved by $19.4 million, reducing the deficit to $42.5 million as at September 30, 2024, compared to a deficit of $61.9 million at year-end 2023.

The Company believes that its net working capital balances in conjunction 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 of September 30, 2024, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the PIL Loan Facility. Abandonment funds will satisfy abandonment obligations and are expected to be released in the long-term as assets are abandoned. Abandonment funding requirements are updated annually. As of September 30, 2024, the Company's restricted cash position was $34.8 million, representing an increase of $4.5 million from December 31, 2023, primarily due to the increase in the debt service reserve account of the PIL Loan Facility, partially compensated by the finalization of the debt service reserve account of the PetroSud Debt, used in full to support the repayment.

The measures taken by the Company to manage its liquidity and capital resources are ongoing and the Company continues to look for additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of such measures, the Company expects that unrestricted cash balances in conjunction with future cash flows from operations, available credit facilities, and alternate 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 can make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 35.

Unsecured Notes

The Company's long-term borrowing consists of the outstanding unsecured notes due on June 21, 2028 (the "**2028 Unsecured Notes**") in the aggregate principal amount of $400.0 million which were issued on June 21, 2021. 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.

During the nine months ended September 30, 2024, the Company repurchased in the open market $5.0 million, of its 2028 Unsecured Notes for a cash consideration of $4.0 million, including interests. As a result, during the nine months ended September 30, 2024, the Company recognized a gain of $1.0 million. The carrying value for the 2028 Unsecured Notes as at September 30, 2024, is $389.4 million (December 31, 2023: $393.7 million).

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

Unsecured Notes Covenants

The 2028 Unsecured Notes are senior, unsecured notes and rank equal in right of payment with all existing and future senior unsecured debt. As at September 30, 2024, the 2028 Unsecured Notes were guaranteed by the Company's subsidiary, Frontera Energy Colombia Corp. ("**Frontera Colombia**"). On April 11, 2023, the Company designated Frontera Energy Guyana Holding Ltd. and Frontera Guyana as an unrestricted subsidiary and released Frontera Guyana as a note guarantor under the indenture governing the 2028 Unsecured Notes (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. In the event that these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $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 September 30, 2024, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $415,387,000 as of September 30, 2024, and for the last twelve months ended as of September 30, 2024, a consolidated adjusted EBITDA of $428,984,000 and a consolidated interest expense of $45,853,000.

(1) Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the Indenture as the consolidated total indebtedness as of 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 income (loss) (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 recent period ended 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 a measure of overall financial strength. Consolidated total indebtedness is defined as long-term debt, plus liabilities for leases and 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 are exclusive of 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 September 30 2024
Short-term and Long-term debt (1)	$	407,446
Total lease liabilities (2)		12,742
Risk management asset net (3)		(4,801)
Consolidated Total Indebtedness		**415,387**
(-) Cash and Cash Equivalents (4)		(148,344)
(=) Net Debt	**$**	**267,043**

(1) Excludes $110.0 million of long-term debt attributable to the Unrestricted Subsidiaries.

(2) Excludes $1.3 million of lease liabilities attributable to the Unrestricted Subsidiaries.

(3) Excludes $0.6 million of risk management asset attributable to the Unrestricted Subsidiaries.

(4) Includes unrestricted cash and cash equivalents attributable to the guarantors as of September 30, 2024, Frontera Energy Colombia AG and the issuer (i.e., the Company) according to the Indenture.

Pipeline Investment Loan Facility

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

The PIL Loan Facility was recognized net of an original issue discount of $5.1 million, and directly attributable transaction costs of $1.1 million, primarily related to underwriter fees, legal fees, registration fees and other professional fees. In addition, a $10.5 million debt service reserve account for the PIL Loan Facility was constituted.

The proceeds of the PIL Loan Facility were used to repay in full the Puerto Bahia debt facility between Puerto Bahia, Itaú BBA Colombia S.A. and other lenders, maturing in June 2025, which had an outstanding balance plus accrued interest of $106.2 million to pay transaction fees and expenses, and to fund a six-month debt service reserve account (for further information, refer to Note 16 of the 2023 Annual Financial Statements). The PIL Loan Facility has no impact on the Company's financial covenant calculations under the 2028 Unsecured Notes.

On February 16, 2024, as part of the PIL Loan Facility (Tranche A-2), the Company amended the facility to disburse an accordion tranche of $30.0 million. This tranche secures the funding for the Reficar Connection Project. On February 23, 2024 and August 7, 2024, the lenders disbursed $8.8 million and $10.0 million, respectively, and additional resources of $10.0 million are expected to be disbursed in the fourth quarter of 2024. The accordion tranche was recognized, net of an original issue discount of $1.2 million, primarily related to lenders and legal fees discounted at the disbursement.

As at September 30, 2024, the carrying value of the PIL Loan Facility was $110.0 million (December 31, 2023: $95.6 million) which includes short-term debt of $33.7 million. As at September 30, 2024 the PIL Loan Facility debt service reserve account had a balance of $17.8 million. (December 31, 2023: $11.3 million).

Bancolombia Working Capital Loan

On October 24, 2023, the Company entered into a one-year working capital loan agreement with Bancolombia S.A. ("**Bancolombia**"), denominated in COP, with a principal amount of COP 75,000 million (equivalent to $18.2 million), maturing on October 30, 2024, with an interest rate of IBR[(1)] + 4.00%, payable quarterly (the "**Bancolombia Working Capital Loan**"). On October 30, 2023, Bancolombia disbursed the total amount of the loan. The proceeds of the Bancolombia Working Capital Loan were intended for general corporate purposes. In connection to the Bancolombia Working Capital Loan, the Company entered into a FX forward on October 31, 2023, hedging the original loan amount at a forward rate of COP 4,386.17, with a maturity date of October 29, 2024.

As at September 30, 2024, the carrying value of the Bancolombia Working Capital Loan was $17.8 million (2023: $19.6 million). Following the end of the quarter, the Bancolombia Working Capital Loan has been paid in full.

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

PetroSud Loans

On December 30, 2021, the Company acquired 100% of the issued and outstanding shares of Petroleos Sud Americanos S.A. ("**PetroSud**"). For further information, refer to Note 4 of the 2022 Annual Consolidated Financial Statements.

On March 15, 2019, and December 20, 2021, PetroSud entered into two credit agreements with Banco Davivienda S.A. ("**Banco Davivienda**") for a principal amount of $22.0 million and $2.8 million, respectively (the "**PetroSud Debt**").

On March 11, 2024 and May 23, 2024, the Company prepaid the outstanding balance of $5.9 million and $2.8 million, respectively to Banco Davivienda. As of September 30, 2024, the PetroSud Debt was paid in full. PetroSud and Frontera have no obligation under the former PetroSud Debt, and there are no additional restricted funds related to the PetroSud Debt.

Letters of Credit

The Company has various uncommitted bilateral letters of credit. As of September 30, 2024, the Company had issued letters of credit and guarantees for exploration and abandonment funds totalling $120.4 million (total credit lines of $154.8 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, amounting to $6.1 million as at September 30, 2024, and matures date of 72 months from April 3, 2024. The Solar Plant Debt bears interest equivalent to IBR +5.75%, payable monthly over the outstanding amount. As at September 30, 2024, the outstanding balance was $6.0 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 entered into 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, amounting to $0.9 million as at September 30, 2024, and has a maturing on April 9, 2029. The BESS Project leasing bears interest equivalent to IBR +5.10%, payable monthly. As at September 30, 2024, the outstanding balance was $0.7 million. The Company recognized this obligation as a lease liability.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at September 30, 2024, undiscounted by calendar year, are presented below:

As at September 30, 2024 ($M)	2024	2025	2026	2027	2028	2029 and Beyond	Total
Short-term and long-term debt principal and interest	65,508	61,155	58,824	80,006	420,660	—	686,153
Lease liabilities	5,275	5,214	2,745	2,256	1,991	1,239	18,720
Total financial obligations	**70,783**	**66,369**	**61,569**	**82,262**	**422,651**	**1,239**	**704,873**
Transportation							
Ocensa P-135 ship-or-pay agreement	18,364	36,578	—	—	—	—	54,942
ODL agreements	153	358	—	—	—	—	511
Other transportation and processing commitments	4,125	14,206	12,193	—	—	—	30,524
Exploration and evaluation							
Minimum work commitments [1] [2]	300	20,315	9,871	5,066	—	—	35,552
Other commitments							
Operating purchases, community obligations and others	54,100	928	574	335	259	2,732	58,928
Commitments energy supply	3,415	19,253	8,927	5,051	—	—	36,646
Total Commitments	**80,457**	**91,638**	**31,565**	**10,452**	**259**	**2,732**	**217,103**

[1] Includes minimum work commitments relating to exploration activities in Colombia until the contractual phase, when the Company will decide whether to continue or relinquish the exploration areas.

[2] On October 8, 2024 the Company received a communication from the ANH accepting the termination of the CAG-5 contract by mutual agreement, as a result the $40.4 million commitment has been removed.

During the third quarter in Ecuador, two exploration wells were completed in the Espejo Block, as a result the $13.0 million commitment has been removed.

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 August 23, 2024, the term of the pledge agreement was extended to December 31, 2024 with Ocensa and to January 31, 2025 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. No material changes have occurred regarding the matters disclosed in Note 25 - Commitments and Contingencies of the 2023 Annual Consolidated Financial Statements.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at November 6, 2024:

	Number
Common shares	80,793,387
DSUs (1)	1,033,223
RSUs (2)	2,049,338

(1) DSUs represent a future right to receive Common Shares (or the cash equivalent) at the time of the holder's retirement, death or the holder otherwise ceasing to provide services to the Company. Each DSU awarded by the Company approximates the fair market value of a Common Share at the time the DSU is awarded. The value of a DSU increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of a DSU holder with shareholders. DSUs are settled in Common Shares, cash or a combination thereof, as determined by the Compensation and Human Resources Committee of the Board (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 as determined by the established vesting conditions. RSUs are granted with vesting conditions that are 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 increases or decreases, thereby promoting alignment of interests of an RSU holder with 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 Bid ("NCIB")

On November 21, 2023, the Company launched an NCIB (the "**2023 NCIB**"), pursuant to which the Company may 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 twelve-month period commencing November 21, 2023, and ending on November 20, 2024. On September 4, 2024, the Company suspended repurchases under the 2023 NCIB in connection with the SIB. Subject to the acceptance of the TSX, the Company intends to renew NCIB for another year.

On March 17, 2022, the Company launched an NCIB ("**2022 NCIB**"), pursuant to which the Company could purchase for cancellation up to 4,787,976 of its Common Shares, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules) as at March 7, 2022 during the twelve-month period commencing March 17, 2022 and ending March 16, 2023.

Purchases subject to both NCIBs were or are 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. During the three and nine months ended September 30, 2024, the Company repurchased a total of 374,200 Common Shares and 1,271,600 Common Shares, respectively, pursuant to the 2023 NCIB. As at November 6, 2024, the Company had repurchased for cancellation a total of 1,552,100 Common Shares under 2023 NCIB for approximately $9.5 million with an additional 2,397,354 Common Shares remaining available for repurchase under the 2023 NCIB. Under the 2022 NCIB that expired on March 16, 2023, the Company repurchased for cancellation during the twelve-month term a total of 4,270,100 Common Shares, for approximately $40.9 million.

The following table provides a summary of total share repurchases under the 2023 NCIB program:

	Nine Months Ended September 30
	2024
Number of Common Shares repurchased	1,271,600
Total amount of Common Shares repurchased ($M)	7,823
Weighted-average price per share ($) (1)	6.15

(1) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures'' section on page 24.

Substantial Issuer Bid

On September 4, 2024, the Company announced that its board of directors has approved the commencement of a SIB pursuant to which the Company offered to purchase from shareholders of Common Shares of the Company up to 3,375,000 Common Shares for cancellation at a purchase price of CAD$12.00 per share, for an aggregate purchase price up to CAD$40.5 million (equivalent to $30.0 million). The bid expired on October 17, 2024.

On October 22, 2024, the Company announced that in accordance with the terms and conditions of the SIB, Frontera has taken 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 of October 17, 2024) at a price of CAD$12.00 per Common Share, representing an aggregate purchase price of approximately CAD$40.5 million. After the cancellation of the Common Shares taken up and paid for by the Company, approximately 80.78 million Common Shares will be issued and outstanding.

On November 6, the Company announced its intention to commence the New SIB pursuant to which the Company will offer to purchase up to $30 million of its Common Shares for cancellation at a fixed price per share.

The Company intends to determine the terms of the New SIB, including pricing, in due course, and expects that the New SIB will be completed in January 2025. Commencement and/or completion of the New SIB is subject to receipt of a satisfactory liquidity opinion from a qualified financial adviser, approval of the Board of Directors, and obtaining any necessary exemptive relief under applicable securities laws in Canada. The New SIB will not be conditional upon any minimum number of shares being tendered and will be subject to conditions customary for transactions of this nature. The Company intends to fund the New SIB from current cash resources.

Dividends

On March 7, 2024, the Company adopted a dividend policy that includes an initial cash dividend of C$0.0625 per Common Share, or $3.9 million. This dividend payment to shareholders is designated as an "eligible dividend" under the Income Tax Act (Canada). The declaration and payment of any specific quarterly dividend remain at the discretion of the Company's board of directors.

The Company´s dividends paid or declared during the nine months ended September 30, 2024, 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	3,907	—
May 7, 2024	July 3, 2024	July 17, 2024	0.0625	3,892	626
August 6, 2024	October 2, 2024	October 16, 2024	0.0625	3,861	531

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

Subsequently, pursuant to Frontera's dividend policy, Frontera's Board of Directors has declared a dividend of C$0.0625 per Common Share to be paid on or around January 17, 2025, to shareholders of record at the close of business on January 3, 2025.

6. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding, commitments and transactional amounts with related parties as at September 30, 2024 and December 31, 2023, and for the three and nine months ended September 30, 2024, and 2023, respectively:

		As at September 30, 2024 and December 31, 2023			Three Months Ended September 30	Nine Months Ended September 30
($M)		Receivables from Investment	Accounts Payable	Commitments	Purchases / Services	
ODL	2024	17,587	2,591	511	7,061	22,035
	2023	—	3,141	2,380	7,960	22,749

The related-party transactions correspond to the ship-and-pay contract for the transportation of crude oil in Colombia and ship-or-pay for other services for a total commitment of $0.5 million until 2025.

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/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 plans, identifies, evaluates, prioritizes and monitors risk across the organization and supports decision-making. This program identifies critical strategic risk to its people, its assets, operation, regulatory environment, health, safety and environment, liquidity, communities and political landscape, and seeks to systematically mitigate these risks to an acceptable level. In addition, we continuously monitor our risk profile as well as industry best practices.

During the fourth quarter 2023, the Board approved a restructuring plan (the "**Restructuring Plan**"), designed to drive operational efficiencies, reduce operating costs and better align the Company's workforce with current business needs, top strategic priorities, and key growth opportunities. The Restructuring Plan included the reduction of the Company's workforce by approximately 16%. The Company may encounter challenges in the execution of these restructuring efforts that could prevent it from recognizing the intended benefits of the Restructuring Plan or otherwise adversely affect its business, results of operations and financial condition. As a result of the Restructuring Plan, the Company has incurred and may continue to incur additional costs in the short-term, including cash expenditures for employee transition, notice period and severance payments, employee benefits and related costs. These additional expenditures could have the effect of reducing the Company's operating margins. The Restructuring Plan may result in other unintended consequences. If the Company experiences any of these adverse consequences, the Restructuring Plan may not achieve or sustain its intended benefits, or the benefits, even if achieved, may not be adequate to meet the Company's long-term profitability and operational expectations, which could adversely affect the Company's business, results of operations and financial condition.

See the "Liquidity and Capital Resources" section on page 30 for additional detail 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 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, although there can be no assurance that any such initiative or transaction will occur or if it occurs, the timing thereof.

The information above does not contain all the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, please see the Company's AIF and the 2023 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 1 of the CPA Canada Handbook Accounting. A summary of significant accounting policies applied is included in Note 3a of the 2023 Annual Consolidated Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 3b of the 2023 Annual Consolidated Financial Statements, including management's evaluation of 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, 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 and 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 and the reported amounts of revenues and other items.

The effect of the global economy, including the impact of the Russia-Ukraine conflict, the Middle East conflict, and the associated volatility in oil prices, could have negative impacts on the Company. The uncertainty these events bring has resulted in a challenging economic environment, with more volatile commodity prices, foreign exchange rates and long-term interest rates. The outcome of the conflict in the Middle East continues to be uncertain and has the potential to have wide-ranging consequences on the world economy. Global oil prices have remained highly volatile since the beginning of the Middle East conflict. There is a risk that the conflict could lead to wider regional instability in the Middle East, home to some of the world's biggest oil producers. 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 conflict remain uncertain, and the Company continues to monitor the evolving situation. On the other, these events also undermine economic conditions and exacerbate inflation in several economies, directly impacting the cost of goods and services. 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 has 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. As such, actual results may differ from these estimates under different assumptions or conditions. A summary of the key accounting estimates and judgments made by management in the preparation of its financial information is provided in Note 3c of the 2023 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 52-109F2. 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 control and procedures ("**DC&P**") and internal controls 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 are 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 because of inherent limitations.

Management of the Company has evaluated the effectiveness of the Company's ICFR for the period beginning July 2024 and ending September 30, 2024. Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at September 30, 2024.

There has been no change in the Company's ICFR during the period beginning on April 1, 2024 and ended on September 30, 2024, 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 its Chief Financial Officer, concluded that the Company's DC&P were effective as at September 30, 2024.

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		**Q3 2024**	**Q2 2024**	**Q3 2023**	**2024**	**2023**
Quifa	(bbl/d)	16,778	17,371	17,873	17,002	17,751
CPE-6	(bbl/d)	7,459	6,947	5,803	6,880	5,260
Guatiquia	(bbl/d)	5,801	5,539	6,763	5,651	7,104
Vim1	(boe/d)	1,934	1,856	1,798	1,790	1,728
Perico	(bbl/d)	1,470	1,655	652	1,534	662
Cubiro	(bbl/d)	1,447	1,491	1,729	1,466	1,940
Cravoviejo	(bbl/d)	1,331	1,314	1,563	1,331	1,628
Casimena	(bbl/d)	1,077	1,165	1,269	1,150	1,316
Other blocks	(boe/d)	3,319	2,574	3,352	2,774	4,088
Total production	**(boe/d)**	**40,616**	**39,912**	**40,802**	**39,578**	**41,477**

Production Reporting

Production volumes are reported on a Company's W.I. before royalties basis. In Ecuador, the government has a variable share over the total volumes produced under Perico and Espejo joint venture exploration and extraction contracts. The Company has reported this share of production retained by the government under the contract, as royalties paid in-kind in this MD&A.

The following table includes the average net production:

		Net Production				
					Nine months ended September 30	
Producing blocks in Colombia		**Q3 2024**	**Q2 2024**	**Q3 2023**	**2024**	**2023**
Heavy crude oil	(bbl/d)	22,324	21,534	21,575	21,573	20,876
Light and medium crude oil combined	(bbl/d)	9,647	9,496	11,875	9,635	13,011
Conventional natural gas	(mcf/d)	3,192	4,019	5,250	3,494	6,475
Natural gas liquids	(boe/d)	1,521	1,651	1,686	1,562	1,539
Net production Colombia	**(boe/d)**	**34,052**	**33,386**	**36,057**	**33,383**	**36,562**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	1,215	1,119	460	1,125	532
Net production Ecuador	**(bbl/d)**	**1,215**	**1,119**	**460**	**1,125**	**532**
Total net production	**(boe/d)**	**35,267**	**34,505**	**36,517**	**34,508**	**37,094**

Boe Conversion

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used 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 has been expressed using the Colombian conversion standard of 5.7 Mcf: 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 the production rates 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 are 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 done.

Abbreviations

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

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