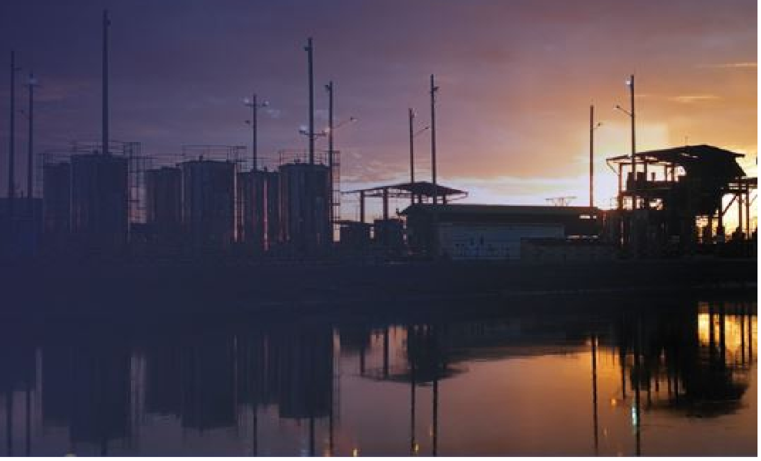
MANAGEMENT DISCUSSION & ANALYSIS

May 8, 2024
For the three months ended March 31, 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 months ended March 31, 2024 and 2023 (the"**Interim Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form (**"AIF"**), have been filed with Canadian securities regulatory authorities and are available on SEDAR+ at www.sedarplus.ca and on the Company's website at www.fronteraenergy.ca. Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.*

*The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board, unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These non-IFRS financial measures are described in greater detail under the heading "Non-IFRS and Other Financial Measures" section on page 24.*

*This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to activities, events or developments that the Company believes, expects or anticipates will or may occur in the future. Forward-looking information in this MD&A includes, without limitation, statements regarding estimates and/or assumptions in respect of the oil price environment, current and expected impacts of COVID-19 or any other pandemic, 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, 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 thereof), operating EBITDA, production costs, transportation costs, the restructuring plan, cost savings, including General and Administrative ("**G&A**") expense savings, 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; the current and potential adverse impacts of COVID-19 or any other pandemic; the performance of assets and equipment; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour, services and infrastructure; and the development and execution of projects.

Although the Company believes that the assumptions inherent in the forward-looking information are reasonable, forward-looking information is not a guarantee of future performance and accordingly undue reliance should not be placed on such information. Forward-looking information is subject to a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to the Company. The actual results of the Company may differ materially from those expressed or implied by the forward-looking information, and even if such actual results are realized or substantially realized, there can be no assurance that they will have the expected consequences to, or effects on, the Company. Factors that could cause actual results or events to differ materially from current expectations include, among other things: volatility in market prices for oil and natural gas; measures the Company has taken and continues to take or may take in response to pandemics; the 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

		Q1 2024	Q4 2023	Q1 2023
Operational Results				
Heavy crude oil production [1]	(bbl/d)	23,398	23,002	22,270
Light and medium crude oil combined production [1]	(bbl/d)	12,580	13,795	16,518
Total crude oil production	(bbl/d)	35,978	36,797	38,788
Conventional natural gas production [1]	(mcf/d)	3,283	4,760	8,590
Natural gas liquids production [1]	(boe/d)	1,639	1,635	1,291
Total production [2]	(boe/d) [3]	38,193	39,267	41,586
Total inventory balance	(bbl)	1,278,763	1,076,394	1,611,201
Brent price reference	($/bbl)	81.76	82.85	82.10
Oil and gas sales, net of purchases [4]	($/boe)	73.71	75.76	69.07
Premiums paid on oil price risk management contracts [5]	($/boe)	(1.27)	(0.69)	(1.16)
Royalties [5]	($/boe)	(1.64)	(1.79)	(3.36)
Net sales realized price [4]	($/boe)	70.80	73.28	64.55
Production costs (excluding energy cost), net of realized FX hedge impact [4]	($/boe)	(10.21)	(9.69)	(8.12)
Energy costs, net of realized FX hedge impact [4]	($/boe)	(5.29)	(5.06)	(3.95)
Transportation costs, net of realized FX hedge impact [4]	($/boe)	(11.33)	(11.02)	(11.20)
Operating netback per boe [4]	($/boe)	43.97	47.51	41.28
Financial Results				
Oil & gas sales, net of purchases [6]	($M)	202,469	240,105	189,120
Premiums paid on oil price risk management contracts	($M)	(3,489)	(2,198)	(3,175)
Royalties	($M)	(4,506)	(5,683)	(9,213)
Net sales [6]	($M)	194,474	232,224	176,732
Net (loss) income [7]	($M)	(8,503)	92,038	(11,330)
Per share – basic	($)	(0.10)	1.08	(0.13)
Per share – diluted	($)	(0.10)	1.04	(0.13)
General and administrative	($M)	13,556	16,891	12,669
Outstanding Common Shares	Number of Shares	84,693,416	85,151,216	85,188,573
Operating EBITDA [6]	($M)	97,248	121,036	91,922
Cash provided by operating activities	($M)	65,616	73,432	845
Capital expenditures [6]	($M)	69,381	82,292	131,452
Cash and cash equivalents – unrestricted	($M)	154,907	159,673	162,272
Restricted cash short and long-term [8]	($M)	27,058	30,300	30,877
Total cash [8]	($M)	181,965	189,973	193,149
Total debt and lease liabilities [8]	($M)	537,151	536,822	519,471
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [9]	($M)	429,556	430,170	400,361
Net debt (excluding Unrestricted Subsidiaries) [9]	($M)	305,821	318,092	279,843

[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* ("**NI 51-101**").
[2] Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 38.
[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 38.
[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 (loss) income 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, 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 is centered on maximizing and realizing value through its strategic portfolio of energy and infrastructure related assets as captured by its three core businesses:

- **Colombian and Ecuador Upstream**: cash flow-focused production and reserves management from large 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 providing stable and long-term revenue streams; and
- **Guyana Exploration**: potentially transformational offshore Guyana opportunity for a Maastrichtian-based, stand-alone commercial development, with upside and future opportunities in the deeper zones.

First Quarter of 2024

Frontera delivered average daily production of 38,193 boe/d (consisting of 23,398 bbl/d of heavy crude oil, 12,580 bbl/d of light and medium crude oil combined, 3,283 mcf/d of conventional natural gas and 1,639 boe/d of natural gas liquids), and invested $69.4 million in capital expenditures including $35.0 million on development drilling in the Quifa, CPE-6 and Perico blocks. Frontera generated strong operating EBITDA of $97.2 million and saw ending inventories increase by 0.2 MMbbl as compared to the prior quarter.

The Company's production was affected primarily by light & medium oil performance, partially offset by resilient heavy crude oil operations despite community blockades and delays related to strategic water disposal initiatives. The Company brought production back online successfully and restarted activity during the month of February. Despite these challenges, Frontera saw a 2% increase in heavy crude oil production quarter over quarter and achieved another quarterly production record in the CPE-6 block of 6,228 bbl/d. In Ecuador, production remained strong averaging 1,478 bbl/d in the first quarter of 2024 as compared to 1,453 bbl/d in the fourth quarter of 2023.

Frontera achieved an agreement in principle with Ecopetrol S.A. ("**Ecopetrol**") for the use by the Quifa Block of the Company's reverse osmosis water treatment facility ("**SAARA**") for a two-year period increasing water disposal capacity for the block. During this phase, SAARA's objetive is to treat and dispose 250,000+ bwpd for the Quifa block. Increasing water handling capacity at Quifa is key to Frontera's efforts to grow production at Quifa. In connection with this agreement, SAARA will seek to increase flow lines providing irrigation source water to the Company's nearby Promotora Agricola de los Llanos S.A. ("**ProAgrollanos**") palm oil plantation.

First quarter production costs (excluding energy cost), net of realized FX hedge impact, averaged $10.21/boe versus $9.69/boe in the prior quarter mainly driven by higher well services activity, inflationary pressures on services and wage indexation. The Company's energy costs, net of realized FX hedge impact, averaged $5.29/boe versus $5.06/boe in the prior quarter due to sustained high energy prices and higher activity in the heavy oil assets. In addition, transportation costs, net of realized FX hedge impact, increased mainly due to the annual transportation tariffs increase.

First quarter 2024 Adjusted Infrastructure EBITDA was $25.7 million, decreasing from $27.3 million during the fourth quarter of 2023. Volumes pumped at the oil pipeline facility at ODL were 246,042 bbl/d, versus 252,810 bbl/d in the prior quarter as a result of lower regional oil volumes at Puerto Gaitan due to the temporary production disruptions associated with the blockades. Puerto Bahia liquids volumes remained strong at 53,360 bbl/d, up slightly from 52,754 bbl/d in the prior quarter, while the general cargo segment experienced lower roll-on/ roll-off ("**RORO**") and Break Bulk volumes. On March 18, 2024, Oleoducto de los Llanos Orientales ("**ODL**") declared dividends and return of capital of $179.6 million ($62.8 million, net for PIL) payable in installments during 2024. In April 2024, PIL received the first installment equal to 50% of the total capital distributions declared.

During the first quarter 2024, Frontera's Sustainability Strategy, reached nearly 50% of CO2 emissions offsetting, through carbon credits, from the production and consumption of energy in our operations. The Colombian Safety Council recognized the Company with its Culture Award for its extensive and robust model of safety and health culture. During the quarter, the company also achieved a TRIR of 0.72, reused 20% of its water production and 37% of its operating waste. Also invest $0.5 million in projects in communities near its operations in Colombia, Ecuador and Guyana.

On February 22, 2024, Frontera was recognized by Ethisphere as one of the World's Most Ethical Companies. This is the fourth consecutive year that the Company has received this distinction from Ethisphere, a global leader in defining and advancing the standards of ethical business practices. In 2024, 136 honorees were recognized from 20 countries and 44 industries. Frontera was one of only two honorees from the oil and gas industry. Frontera was also recognized for the second time as one of the 20 Best Workplaces for Women in Colombia by the Great Place to Work® Institute ("GPTW").

As announced, Frontera remains committed to unlocking value and enhancing shareholder returns. On March 7, 2024, the Board approved the declaration and payment of a dividend of approximately $3.9 million, corresponding to CAD$0.0625 per Common Share, which was paid on April 16, 2024. In addition, the Company repurchased in the open market a portion of its 2028 Unsecured Notes, for cash consideration of $1.2 million. Additionally, pursuant to Frontera's dividend policy, the Board has declared a dividend of CAD$0.0625 per Common Share to be paid on or around July 17, 2024, to shareholders of record at the close of business on July 3, 2024.

In May 2024, the Company launched a strategic alternatives review for its standalone and growing Infrastructure Business, which could result in a potential spin-off to Frontera shareholders, a total or partial sale or other business combination of Frontera's Infrastructure Business, and/or a strategic investment, therein by a third party. Frontera has retained Goldman Sachs & Co. as financial advisor and may retain other advisors to assist the Board in evaluating the various strategic, business, and financial alternatives.

The Company, with support from Houlihan Lokey, continues to actively pursuing strategic alternatives for its interests in the Corentyne block in Guyana, including a possible farm down.

These processes are central to the Company's efforts to streamline the business and unlock the value from sum of its parts. Frontera believes the value of these assets is not reflected in the current stock price and these processes aim to drive value for shareholders. There can be no guarantee that these strategic review processes will result in a transaction.

Financial and Operational Results

- Production averaged 38,193 boe/d in the first quarter of 2024 (consisting of 23,398 bbl/d of heavy crude oil, 12,580 bbl/d of light and medium crude oil combined, 3,283 mcf/d of conventional natural gas and 1,639 boe/d of natural gas liquids), compared to 39,267 boe/d in the prior quarter (consisting of 23,002 bbl/d of heavy crude oil, 13,795 bbl/d of light and medium crude oil combined, 4,760 mcf/d of conventional natural gas and 1,635 boe/d of natural gas liquids), and compared to 41,586 boe/d in the first quarter of 2023 (consisting of 22,270 bbl/d of heavy crude oil, 16,518 bbl/d of light and medium crude oil combined, 8,590 mcf/d of conventional natural gas and 1,291 boe/d of natural gas liquids).

- Cash provided by operating activities was $65.6 million in the first quarter of 2024, compared with $73.4 million in the prior quarter, and $0.8 million in the first quarter of 2023. The Company reported a total cash position of $182.0 million, including $27.1 million of restricted cash, as at March 31, 2024, compared with a total cash position of $193.1 million, including $30.9 million of restricted cash, as at March 31, 2023.

- The Company recorded a net loss(1) of $8.5 million ($0.10/share(2)) in the first quarter of 2024, compared with net income of $92.0 million ($1.04/share(2)) in the prior quarter and net loss(1) of $11.3 million ($0.13/share(2)) in the first quarter of 2023.

- Capital expenditures were $69.4 million in the first quarter of 2024, compared with $82.3 million in the prior quarter and $131.5 million in the first quarter of 2023.

- Operating EBITDA was $97.2 million in the first quarter of 2024, compared with $121.0 million in the prior quarter and $91.9 million in the first quarter of 2023.

- Operating netback was $43.97/boe in the first quarter of 2024, compared with $47.51/boe in the prior quarter and $41.28/boe in the first quarter of 2023.

- Infrastructure Colombia segment income was $12.6 million in the first quarter of 2024, compared with $13.2 million in the prior quarter and $16.0 million in the first quarter of 2023.

- Adjusted Infrastructure EBITDA in the first quarter of 2024 was $25.7 million, compared with $27.3 million in the prior quarter and $27.4 million during the first quarter of 2023.

- Puerto Bahia liquids volumes handled during the first quarter of 2024 were 53,360 bbl/d compared to 52,754 bbl/d in the prior quarter and 63,008 bbl/d in the first quarter of 2023. Puerto Bahia revenues were $9.7 million during the first quarter 2024, compared to $10.1 million in the prior quarter and $10.8 million during the first quarter of 2023.

- Total ODL volumes transported during the first quarter of 2024 were 246,042 bbl/d compared to 252,810 bbl/d in the prior quarter and 225,792 bbl/d in the first quarter of 2023. During the three months ended March 31, 2024, the Company recognized gross dividends of $54.9 million and recognized a return of capital of $7.9 million, compared with $Nil of gross dividends and $5.1 million of return of capital in the prior quarter, and $37.0 million of gross dividends and $5.2 million of return of capital in the first quarter of 2023.

(1) Net (loss) income 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 three months ended March 31, 2024, against the full year 2024 guidance metrics as released on February 15, 2024.

We reiterate our production and capital guidance for 2024. Our 2024 drilling campaign continues to progress well and we expect improved production and profitability throughout the rest of the year as we advance our development portfolio in Colombia and Ecuador and increase Quifa and CPE-6 water-handling infrastructure and facilities.

		2024	
		Guidance	**Actual**
Average Daily Production[1]	boe/d	40,000 - 42,000	38,193
Production Costs (excluding energy cost) [2][4]	$/boe	8.50 - 9.50	10.21
Energy Costs [2][4]	$/boe	5.75 - 6.25	5.29
Transportation Costs[3][4]	$/boe	11.00 - 12.00	11.33
Operating EBITDA[5] at $80/bbl [6]	$MM	400 - 450	97.2
Adjusted Infrastructure EBITDA[8]	$MM	95 - 115	25.7
Development Drilling	$MM	85 - 95	35.0
Development Facilities	$MM	95 - 115	19.7
Colombia and Ecuador Development	$MM	180 - 210	54.7
Colombia and Ecuador Exploration	$MM	35 - 45	2.2
Other [9]	$MM	15 - 25	6.3
Total Colombia & Ecuador Upstream Capex	$MM	230 - 280	63.2
Colombia Infrastructure[10]	$MM	40 -50	4.6
Guyana Exploration	$MM	2 - 5	1.5
Total Capital Expenditures[11]	$MM	272 - 335	69.3

[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] Includes Puerto Bahia (including FEC-related revenues), SAARA and ProAgrollanos.
[8] 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.
[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 operated by Refineria de Cartagena S.A.S. ("**Reficar**") the ("**Reficar Connection Project**"), 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 38 for details of the Company's net production.

		Production		
Producing blocks in Colombia		**Q1 2024**	**Q4 2023**	**Q1 2023**
Heavy crude oil	(bbl/d)	23,398	23,002	22,270
Light and medium crude oil combined	(bbl/d)	11,102	12,342	15,513
Conventional natural gas	(mcf/d)	3,283	4,760	8,590
Natural gas liquids	(boe/d)	1,639	1,635	1,291
Total production Colombia	**(boe/d)**	**36,715**	**37,814**	**40,581**
Producing blocks in Ecuador				
Light and medium crude oil combined	(bbl/d)	1,478	1,453	1,005
Total production Ecuador	**(bbl/d)**	**1,478**	**1,453**	**1,005**
Total production	**(boe/d)**	**38,193**	**39,267**	**41,586**

Colombia

For the three months ended March 31, 2024, production in Colombia decreased by 1,099 boe/d, compared to the prior quarter.

Heavy crude oil production, increased 2% mainly due higher activity, greater production and water disposal capacity in both the CPE-6 and Quifa block, partially offset by, temporary blockades and road closures affecting both the Quifa and CPE-6 blocks. As a result of the blockades, certain Company's wells had to be shut impacting the quarter's production by approximately 435 bbl/d. Additionally, reduced water disposal capacity associated with SAARA, due to the temporary suspension of the project following the conclusion of the project's pilot program, impacted production by an additional 290 bbl/d.

Light and medium crude oil combined and conventional natural gas production decreased 10% and 31%, respectively, compared to the prior quarter, mainly due to the natural decline and unexpected well failures.

Compared to the three months ended March 31, 2023, production decreased by 3,866 boe/d. Heavy crude oil production increased of 1,128 bbl/d, as a result of the successful development drilling campaign in the CPE-6 and the Quifa blocks, and new water facilities in the CPE-6 block. Natural gas liquids production increased by 27% in the VIM-1 block as a result of the development of the facilities. Light and medium crude oil combined and conventional natural gas production decreased by 28% and 62%, respectively. These declines were mainly due to unexpected well failures, the finalization of the Neiva block production contract in June of 2023 and the natural decline.

Ecuador

Production in Ecuador for the three months ended March 31, 2024, increased by 47% in light and medium crude oil combined, compared to the same period of 2023. The increase is attributed to the completion of the Perico Norte A-3, the Perico Centro 2, and the Perico Norte A-4 wells during the second half of 2023. Compared to the prior quarter, production slightly increased due to the completion of Perico Norte A-5 at the end of February 2024, partially offset by natural decline.

Production Reconciled to Sales Volumes

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

		Q1 2024	Q4 2023	Q1 2023
Production	(boe/d)	**38,193**	**39,267**	**41,586**
Royalties in-kind Colombia [1]	(boe/d)	(4,011)	(5,257)	(4,220)
Royalties in-kind Ecuador [2]	(boe/d)	(439)	(485)	(298)
Net production	(boe/d)	**33,743**	**33,525**	**37,068**
Oil inventory (build) draw	(boe/d)	(2,223)	2,762	(4,138)
Overlift (settlement)	(boe/d)	—	—	(4)
Volumes purchased	(boe/d)	8,354	6,708	7,984
Other inventory movements [3]	(boe/d)	(2,461)	(2,278)	(2,847)
Sales volumes	(boe/d)	**37,413**	**40,717**	**38,063**
Sale of volumes purchased	(boe/d)	(7,228)	(6,268)	(7,639)
Sales volumes, net of purchases	(boe/d)	**30,185**	**34,449**	**30,424**
Oil sales volumes	(bbl/d)	29,610	33,896	28,970
Conventional natural gas sales volumes	(mcf/d)	3,278	3,152	8,288
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**30,185**	**34,449**	**30,424**
Inventory balance				
Colombia [4]	(bbl)	683,335	551,715	1,032,876
Peru	(bbl)	480,200	480,200	480,200
Ecuador	(bbl)	115,228	44,479	98,125
Inventory ending balance	**(bbl)**	**1,278,763**	**1,076,394**	**1,611,201**

(1) Royalties for the CPE-6 block are paid in-kind, since October 2023.
(2) The Company reports the share of production retained by the government of Ecuador as royalties paid in-kind.
(3) Mainly corresponds to operational consumption and quality volumetric compensation.
(4) Includes 0.35 MMbbl of oil produced and 0.33 MMbbl oil for dilution in the first quarter of 2024, 0.32 MMbbl of oil produced and 0.23 MMbbl oil volumes for dilution in fourth quarter of 2023, and 0.71 MMbbl of oil produced and 0.32 MMbbl volumes for dilution in the first quarter of 2023.

The inventory in Colombia for the first quarter of 2024, increased compared with the prior quarter, mainly due to the additional volume of natural gasoline purchased, which will be consumed in the second quarter of 2024. Sales volumes, net of purchases, for the three months ended March 31, 2024, decreased by 12% compared with the prior quarter, due to higher volumes sold in the fourth quarter of 2023, as a consequence of inventory draw down. Volumes sold are comparable with the same period in 2023.

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, 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, 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).

		Q1 2024	Q4 2023	Q1 2023
PAP in kind	(bbl/d)	1,325	2,664	1,460
PAP in cash	(bbl/d)	376	402	793
PAP	**(bbl/d)**	**1,701**	**3,066**	**2,253**
% Production		**4.5 %**	**7.8 %**	**5.4 %**

For the three months ended March 31, 2024, the total PAP decreased compared with the same period of 2023, mainly due to lower production in the Quifa and Guatiquia blocks.

During the first quarter of 2024, PAP in kind decreased compared to the same period of 2023, mainly due to the lower WTI oil benchmark price. For the three months ended March 31, 2024, PAP in cash decreased compared with the same period of 2023, mainly due to a 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 and lower production.

Realized and Reference Prices

		Q1 2024	Q4 2023	Q1 2023
Reference price				
Brent [1]	($/bbl)	81.76	82.85	82.10
Average realized prices				
Realized oil price, net of purchases	($/bbl)	74.45	76.35	71.09
Realized conventional natural gas price	($/mcf)	6.26	6.93	5.04
Net sales realized price				
Oil and gas sales, net of purchases [2]	($/boe)	73.71	75.76	69.07
Premiums paid on oil price risk management contracts[3] [4]	($/boe)	(1.27)	(0.69)	(1.16)
Royalties [3]	($/boe)	(1.64)	(1.79)	(3.36)
Net sales realized price [2]	**($/boe)**	**70.80**	**73.28**	**64.55**

[1] Frontera's weighted average Brent price was $82,35/bbl in 2024.
[2] Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.
[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 months ended March 31, 2024, decreased by $1.09/bbl and $0.34/bbl, compared to the prior quarter and the same period of 2023, respectively. The decrease in crude oil prices during 2024, compared with the same period of 2023, was mainly due to: (i) worldwide economic deceleration creating a lack of demand, (ii) an increase in market supplies in countries such as Guyana, Brazil, Venezuela and the USA, that could not be offset by the OPEC+ cuts, and (iii) the rate interest increase cycles that have not come to an end yet, especially in the USA.

For the three months ended March 31, 2024, the Company's net sales realized price was $70.80/boe. There was a decrease of 3% compared to the prior quarter, driven by the Brent benchmark oil price, higher oil differential prices and premiums paid on oil price risk management contracts, partially offset by lower royalties. In comparison to the same quarter of 2023, the Company's net sales realized price increased from $64.55/boe to $70.80/boe, mainly due to the better oil differential prices and lower royalties partially offset by a decrease in the Brent benchmark oil price.

Operating Netback

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

	Q1 2024		Q4 2023		Q1 2023	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price [1]	194,474	70.80	232,224	73.28	176,732	64.55
Production costs (excluding energy cost), net of realized FX hedge impact [1][2][3]	(35,502)	(10.21)	(35,021)	(9.69)	(30,387)	(8.12)
Energy costs, net of realized FX hedge impact [1][2][4]	(18,387)	(5.29)	(18,267)	(5.06)	(14,770)	(3.95)
Transportation costs, net of realized FX hedge impact [1][2][5]	(34,786)	(11.33)	(33,997)	(11.02)	(37,370)	(11.20)
Operating Netback [1] [2]	**105,799**	**43.97**	**144,939**	**47.51**	**94,205**	**41.28**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases [6]		30,185		34,449		30,424
Production [7]		38,193		39,267		41,586
Net production [8]		33,743		33,525		37,068

[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 $1.3 million, $2.1 million and $Nil of realized FX hedge gain attributable to production costs for the first quarter of 2024, fourth quarter of 2023, and the first quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 15.
[4] Includes $0.6 million, $0.7 million and $Nil of realized FX hedge gain attributable to energy costs for the first quarter of 2024, fourth quarter of 2023, and the first quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 15.
[5]Includes $0.4 million, $0.8 million and $Nil of realized FX hedge gain attributable to transportation costs for the first quarter of 2024, fourth quarter of 2023, and the first quarter of 2023, respectively. See "(Loss) gain on Risk Management Contracts" on page 15.
[6]Sales volumes, net of purchases, excluding sales of third-party volumes.
[7]Refer to the "Production" section on page 9.
[8]Refer to the "Further Disclosures" section on page 38.

The Company's operating netback for the first quarter of 2024 was $43.97/boe, compared to $41.28/boe in the same quarter of 2023. The increase was a result of higher net sales realized prices, partially offset by production costs (excluding energy cost), net of realized FX hedge impact, explained by higher well services activity, inflationary pressures on services and wage indexation; higher energy costs, net of realized FX hedge impact due to an El Niño-related increase in market price, and there was an increase in the transportation costs, net of realized FX hedge impact, per barrel, primarily due to an increase in annual transportation tariffs paid by the Company.

In comparison to the prior quarter, the Company's operating netback decreased from $47.51/boe to $43.97/boe, representing a variation of 7%, mainly due to a lower net sales realized price, higher production costs (excluding energy cost), net of realized FX hedge impact and higher transportation costs, net of realized FX hedge impact, as explained above. In addition, higher energy costs, net of realized FX hedge impact, due to sustained high energy prices and higher activity in the heavy oil assets.

Sales

	Three months ended March 31	
($M)	**2024**	**2023**
Oil and gas sales, net of purchases [1]	202,469	189,120
Premiums paid on oil price risk management contracts [2]	(3,489)	(3,175)
Royalties	(4,506)	(9,213)
Net sales [1]	**194,474**	**176,732**
Net sales realized price ($/boe) [3]	70.80	64.55

(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, increased by $13.3 million for the three months ended March 31, 2024, compared to the same period of 2023, mainly due to better oil differential prices and lower royalties partially offset by a decrease in the Brent benchmark oil price (Refer to the "Realized and Reference Prices" section on page 11 for further details on changes in prices).

Net sales for the three months ended March 31, 2024, increased by $17.7 million, compared with the same period of 2023. The following table describes the various factors that impacted net sales:

	Three months ended March 31
($M)	**2024-2023**
Net sales for the period ended March 31, 2023	176,732
Increase due to 7% higher oil and gas price	12,686
Decrease in royalties	4,707
Increase due to variance of total produced volumes sold	663
Increase in premiums paid on oil price risk management contracts	(314)
Net sales for the period ended March 31, 2024	**194,474**

Oil and Gas Operating Costs

	Three months ended March 31	
($M)	**2024**	**2023**
Production costs (excluding energy cost)	36,839	30,387
Energy cost	18,968	14,770
Transportation costs	35,195	37,370
Post-termination obligation	550	157
Inventory valuation	(3,923)	(8,053)
Total oil and gas operating costs	**87,629**	**74,631**

Total oil and gas operating costs increased by 17% for the three months ended March 31, 2024, compared to the same period 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 March 31, 2024, were 21% higher compared with the same period of 2023, driven by higher well services activity, inflationary pressures on services and wage indexation.
- Energy cost for the three months ended March 31, 2024, increased by 28%, due to an El Niño-related increase in market prices.

- For the three months ended March 31, 2024, transportation costs decreased 6% compared with the same period of 2023, primarily due to lower volumes produced and transported partially offset by the annual transportation tariffs increase.
- Post-termination obligations for the three months ended March 31, 2024, includes the relinquished Orito block of $0.3 million and Block 192 in Peru of $0.2 million.
- Inventory valuation for the three months ended March 31, 2024, increased by $4.1 million, mainly due to lower inventory buildup in the first quarter 2024 compared with the same period of 2023.

Cost of Purchases

	Three months ended March 31	
($M)	**2024**	**2023**
Cost of purchases [(1)]	57,859	59,287

(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 purchases correspond to the cost of third-party hydrocarbon volumes purchased primarily for use in dilution and refining as part of the Company's oil operations, and marketing and transportation strategy. For the three months ended March 31, 2024, the cost of purchases, including the transportation and processing fees for purchased volumes sold, decreased by $1.4 million compared with the same period of 2023, mainly due to a lower volume used and lower Brent benchmark oil prices during the first quarter of 2024.

Royalties

	Three months ended March 31	
($M)	**2024**	**2023**
Royalties Colombia	4,394	9,063
Royalties Ecuador	112	150
Royalties	**4,506**	**9,213**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three months ended March 31, 2024, royalties decreased by $4.7 million compared to the same period 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 10 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended March 31	
($M)	**2024**	**2023**
Depletion, depreciation and amortization	65,812	66,713

For the three months ended March 31, 2024, depletion, depreciation, and amortization expense ("**DD&A**") decreased by 1%, mainly due to a lower production compared to the same period of 2023.

Impairment Expense, Exploration Expenses and Others

	Three months ended March 31	
($M)	**2024**	**2023**
Impairment expense of:		
Exploration and evaluation assets	—	15,164
Other	1,027	1,651
Total impairment expense	1,027	16,815
Exploration expenses of:		
Geological and geophysical costs, and other	410	387
Total exploration expenses	410	387
(Recovery) expense of asset retirement obligations	(1,042)	13,081
Impairment expense, exploration expenses and other	**395**	**30,283**

Total impairment expenses

During the three months ended March 31, 2024, the total impairment expenses was $1.0 million, mainly related to impairment of crude oil inventories from Peru, compared to $15.2 million, during the same quarter of the year 2023, which includes an impairment charge on exploration and evaluation of assets in Colombia, as a result of the relinquishment of the VIM-22 block.

(Recovery) expense 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 months ended March 31, 2024, the Company recognized a recovery of asset retirement obligations of $1.0 million in Colombia. During the three months ended March 31, 2023, the Company recognized an expense of asset retirement obligations of $13.1 million, mainly from the acquisition of the remaining 51% W.I. in Block Z1 in Peru from BPZ Resources. Subsequently in the second quarter of 2023, the Company sold Frontera Energy Offshore Perú, the wholly-owned subsidiary that held a 100% WI in Block Z1.

Other Operating Costs

	Three months ended March 31	
($M)	**2024**	**2023**
General and administrative	13,556	12,669
Special projects and other cost [1]	2,080	2,996
Share-based compensation	286	(160)
Restructuring, severance and other costs	1,803	1,572

[1] Mainly includes costs related to Promotora Agricola de los Llanos S.A., the commissioning of the reverse osmosis water treatment facility "**SAARA**" expansion, and for 2023 included Peru.

General and Administrative ("G&A")

For the three months ended March 31, 2024, G&A expenses increased by 7%, compared with the same quarter of 2023, mainly due to higher professional fees and personnel expenses.

Special projects and other costs

For the three months ended March 31, 2024, special projects and other costs decreased by $0.9 million compared with the same period of 2023, mainly due to Block Z1 costs, in Peru, incurred during the first quarter of 2023.

Share-Based Compensation

For the three months ended March 31, 2024, share-based compensation increased by $0.4 million, compared with the same period of 2023. The increase was mainly due to the cancellation of certain share based compensation during the fist quarter of 2023. Share-based compensation reflects cash and non-cash charges relating to the vesting of 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 majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months ended March 31, 2024, restructuring, severance and other costs increased by $0.2 million, compared with the same period of 2023, mainly due to a reduction of the Company's workforce in line with the Restructuring Plan (as defined below).

Non-Operating Costs

	Three months ended March 31	
($M)	2024	2023
Finance income	1,592	4,301
Finance expenses	(17,270)	(15,221)
Foreign exchange loss	(1,097)	(11,760)
Other (loss) income	(359)	6,305

Finance Income

For the three months ended March 31, 2024, finance income decreased by $2.7 million compared to the same period of 2023, due to lower interest rates on the investment trust accounts for abandonment requirements and lower cash balances during the period.

Finance Expenses

For the three months ended March 31, 2024, finance expenses increased by $2.0 million to the same period of 2023, mainly due to higher interest resulting from the Bancolombia Working Capital Loan (as defined below) and the additional interest resulting from the PIL Loan Facility (as defined below).

Foreign Exchange Loss

For the three months ended March 31, 2024, foreign exchange loss was $1.1 million, as a result of the transfer from the cumulative translation adjustment of the Other Comprehensive Income ("**OCI**") to Consolidated Statement of Income of a return of capital and dividends of Oleoducto de los Llanos S.A. ("**ODL**") during the first quarter of 2024, partially compensated by income related to tax refund collection. During the same period of 2023, the foreign exchange loss was $11.8 million, also resulting from the transfer of a return of capital of ODL from the cumulative translation adjustment of OCI to the Consolidated Statement of Income. Foreign exchange rates (COP:USD) as of March, 31, 2024 and 2023, were 3,842.30:1 and 4,627.27:1, respectively.

Other (Loss) Income

For the three months ended March 31, 2024, the Company recognized other loss of $0.4 million. During the first quarter of 2024, this expense was mainly attributable to contingencies, partially offset by income related to insurance compensation for the Sabanero block. During the same period of 2023, the Company recognized other income of $6.3 million primarily related to a reversal of the legal claim from the late delivery of production from the Quifa block prior to 2014 (for further information refer to the "Commitments and Contractual Obligations" section on page 34).

(Loss) Gain on Risk Management Contracts

	Three months ended March 31	
($M)	2024	2023
Premiums paid on oil price risk management contracts, net	(3,489)	(3,175)
Realized gain on foreign exchange risk hedge [1]	2,615	—
Realized loss on risk management contracts	(874)	(3,175)
Unrealized (loss) gain on risk management contracts	(7,939)	4,825
Total (loss) gain on risk management contracts	(8,813)	1,650

[1] For determination of operating netback, during the three months ended March 31, 2024, the Company estimates an attribution of $1.3 million of the total realized FX hedge to production cost (2023: $Nil), estimates an attribution of $0.6 million of the total realized FX hedge to energy (2023: $Nil), and estimates an attribution of $0.4 million of the total realized FX hedge to transportation (2023: $Nil), respectively. Refer to the "Non-IFRS and Other Financial Measures" section on page 24.

For the three months ended March 31, 2024, the realized loss on risk management contracts was $0.9 million, resulting in $3.5 million related to premiums paid on oil price risk management contracts, partially offset by a gain of $2.6 million on the cash settlement of risk management contracts of foreign exchange currency, compared to a loss of $3.2 million in the same period of 2023, resulting from cash paid for premiums related to put options settled.

During the first quarter of 2024, risk management contracts had an unrealized loss of $7.9 million, compared to a gain of $4.8 million, in the same period 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 price upside. During the first quarter of 2024, the Company successfully achieved a 40% hedging ratio for the April to August 2024 period.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put	April to June 2024	Brent	1,333,492	72.00	—	3,517
Put	July 2024	Brent	452,000	75.00	—	697
Put	August 2024	Brent	430,000	76.50	—	225
Total as at March 31, 2024			2,215,492		—	4,439

Subsequent to March 31, 2024, the Company entered into new hedges that protect a portion of the Company's expected production for September 2024. The new transactions are as follows:

				Avg. Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**
Put	September 2024	Brent	110,000	78.00
		Total volume (bbl)	110,000	

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 to the standard hedging program, the Company entered into a selling forward contract in order to hedge the foreign exchange risk related to the principal payment of the Bancolombia Working Capital Loan (as defined below). As of March 31, 2024, the Company had entered new positions of foreign currency derivatives contracts as follows:

				Avg. Put / Call	Carrying Amount	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume in USD**	**Par forward (COP$)**	**Assets**	**Liabilities**
Zero-cost collars	April to June 2024	USD / COP	60,000,000	4,125/4,763	4,146	—
Forward	October, 2024	USD / COP	17,099,200	4,386	1,744	—
Total as at March 31, 2024					5,890	—

Subsequent to March 31, 2024, the Company entered into new derivatives in order to hedge the currency risk exposure for second half of 2024. The outstanding transactions are as follows:

					Avg. Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Currency Hedged**	**Notional Amount / Volume in USD**	**Par forward (COP$)**
Zero Cost Collars	July to September 2024	USD / COP	USD	30,000,000	3,970/4,056
Forward [(1)]	August 2024	USD / COP	COP	12,056,708	4,044
Forward [(1)]	October 2024	USD / COP	COP	8,965,972	4,078
Forward [(1)]	December 2024	USD / COP	COP	8,885,741	4,115
		Total volume		59,908,421	

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

Income Tax Expense

($M)	Three months ended March 31	
	2024	2023
Current income tax expense	(5,010)	(1,007)
Deferred income tax expense	(21,575)	(6,513)
Total income tax expense	(26,585)	(7,520)

For the three months ended March 31, 2024, the Company recognized a current income tax expense of $5.0 million (2023: $1.0 million), and a deferred income tax expense of $21.6 million (2023: $6.5 million). The increase in income tax expense and deferred income tax expense were primarily due to the impact of non-deductible expenses and foreign currency fluctuations.

Net Loss

($M)	Three months ended March 31	
	2024	2023
Net loss [1]	(8,503)	(11,330)
Per share – basic ($)	(0.10)	(0.13)
Per share – diluted ($)	(0.10)	(0.13)

[1] Refers to Net loss attributable to equity holders of the Company.

During the first quarter of 2024, the Company reported a net loss, attributable to equity holders of the Company, of $8.5 million mainly resulting from income tax expense of $26.6 million (including $21.6 million of deferred income tax expenses), finance expenses of $17.3 million and $8.8 million related to loss on risk management contracts, partially offset by an operating income of $29.7 million, and $13.9 million from share of income from associates. This compared to net loss, attributable to equity holders of the Company, of $11.3 million for the first quarter of 2023, which mainly included operating losses by $2.7 million (including $30.3 million in impairment, exploration expenses and other costs), finance expenses of $15.2 million, foreign exchange losses of $11.8 million and income tax expenses of $7.5 million, partially offset by $13.6 million of share of income from associates and finance income of $4.3 million.

Capital Expenditures and Acquisitions

($M)	Three months ended March 31	
	2024	2023
Development drilling	35,038	31,498
Development facilities	19,678	9,166
Colombia and Ecuador exploration	2,237	12,372
Other	6,334	1,537
Total Colombia and Ecuador upstream capital expenditures	**63,287**	**54,573**
Colombia infrastructure	4,556	1,177
Guyana exploration	1,538	75,702
Total capital expenditures [1]	**69,381**	**131,452**

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

Capital expenditures for the three months ended March 31, 2024, were $69.4 million compared with $131.5 million in the same period of 2023, as follows:

Development drilling. During the three months ended March 31, 2024, development drilling expenditures were $35.0 million, compared to $31.5 million in the same period of 2023. During the first quarter of 2024, 20 development wells were drilled in the Quifa, Cajua and CPE-6 blocks, in Colombia, and 1 development well drilled in the Perico block, in Ecuador. In the same period of 2023, a total of 17 development wells were drilled in the Quifa, Cajua, CPE-6 and Cubiro blocks.

Development facilities. During the three months ended March 31, 2024, development facilities expenditures were $19.7 million mainly related to the Perico block, the increase of water capacity at CPE-6 block, expansion of gas compression facilities in the VIM-1 block, and facilities of injector well in Quifa block. For the same period of 2023, the development facilities expenditures were $9.2 million, related to facilities including the construction of a storage tank at CPE-6 block and the expansion of fluid transfer and the interconnection of fields in the Quifa block.

Colombia and Ecuador Exploration. During the three months ended March 31, 2024, expenditures related to exploration activities were $2.2 million, compared $12.4 million in the same period of 2023. During the three months ended March 31, 2024, the activities executed correspond to the civil work for the platform and road to be prepared for exploration drilling of the Hydra-1 well, at the VIM-1 block, in Colombia and starting activities for drilling 2 exploration wells in the Espejo block, in Ecuador. In the same period of 2023, two exploration wells were completed in Colombia.

Colombia. The Company's exploration focus remains on the Lower Magdalena Valley and Llanos Basins in Colombia. During the first quarter of 2024, pre-drilling activity for the Hydra-1 exploratory well in the VIM-1 block was ongoing. Civil work for the road and platform have been completed, and currently, all goods and services are being secured to spud the well by the end of June 2024. In the Llanos 119 block, the acquisition of 80 sqkm of 3D seismic has commenced and is expected to conclude in the second quarter of 2024. The Company is also engaged in pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-99 and VIM-46 blocks.

Ecuador. At the Espejo block (Frontera holds a 50% W.I. and is a non-operator), as agreed by the Company's partner, the two pending committed exploratory wells will be drilled during the year 2024, targeting one opportunity for Lower U Sand in the southern area and one opportunity for M1 Sand in the central area of the block.

Other

Other capital expenditures for the three months ended March 31, 2024, were $6.3 million, mainly related to facilities funded through the insurance compensation from the Sabanero block.

Colombia infrastructure

Capital expenditures for three months ended March 31, 2024, was $4.6 million mainly related to investments in the SAARA project and investments at Puerto Bahia including (i) general cargo terminal equipment purchases and terminal upgrading, (ii) tank maintenance, and (iii) right of way and engineering expenditure associated to the Reficar Connection Project. During the same period of 2023 capital expenditures was $1.2 million, which includes SAARA project and port facilities investments.

Guyana exploration During the three months ended March 31, 2024, Guyana exploration expenditures were $1.5 million, mainly related to post-well studies, compared to $75.7 million during the same period of 2023.

The Company and its majority-owned subsidiary and Joint Venture (the "**Joint Venture**") partner, CGX, in the petroleum prospecting license for the Corentyne block offshore Guyana (the "**PPL**"), is in the process of concluding the analysis of all technical data collected by Wei-1 dual purpose well. Typical deepwater developments can range from four to seven years from discovery to first oil. The total cost of a typical deepwater project varies greatly depending on several factors that challenge each project. Deepwater projects are more complicated developments that require appraisal drilling and conceptual modeling before a final investment decision ("**FID**") can be made. After FID has been made, it takes approximately three years to complete detailed design/construction/commissioning, prior to the well commencing production. The Joint Venture currently holds a 100% working interest in the Corentyne block.

Selected Quarterly Information

Operational and financial results		2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2
Heavy crude oil production	(bbl/d)	23,398	23,002	24,097	24,051	22,270	22,144	20,945	21,455
Light and medium crude oil combined production	(bbl/d)	12,580	13,795	13,964	15,188	16,518	17,073	17,428	17,348
Total crude oil production	(bbl/d)	35,978	36,797	38,061	39,239	38,788	39,217	38,373	38,803
Conventional natural gas production	(mcf/d)	3,283	4,760	5,250	5,626	8,590	9,097	9,969	10,374
Natural gas liquids production	(boe/d)	1,639	1,635	1,820	1,823	1,291	993	911	963
Total production	(boe/d)	38,193	39,267	40,802	42,049	41,586	41,806	41,033	41,586
Sales volumes, net of purchases	(boe/d)	30,185	34,449	35,289	35,799	30,424	34,323	36,660	33,273
Brent price reference	($/bbl)	81.76	82.85	85.92	77.73	82.10	88.63	97.70	111.98
Oil and gas sales, net of purchases [1]	($/boe)	73.71	75.76	78.48	67.91	69.07	82.60	90.40	102.80
Premiums paid on oil price risk management contracts [2]	($/boe)	(1.27)	(0.69)	(0.59)	(0.80)	(1.16)	(1.32)	(1.30)	(1.15)
Royalties [2]	($/boe)	(1.64)	(1.79)	(3.76)	(3.02)	(3.36)	(6.04)	(7.23)	(10.57)
Net sales realized price [1]	($/boe)	70.80	73.28	74.13	64.09	64.55	75.24	81.87	91.08
Production costs (excluding energy cost), net of realized FX hedge impact [2]	($/boe)	(10.21)	(9.69)	(8.82)	(8.45)	(8.12)	(8.48)	(8.30)	(9.25)
Energy costs, net of realized FX hedge impact [2]	($/boe)	(5.29)	(5.06)	(5.04)	(3.94)	(3.95)	(3.08)	(2.90)	(3.26)
Transportation costs, net of realized FX hedge impact[2]	($/boe)	(11.33)	(11.02)	(11.73)	(10.89)	(11.20)	(10.55)	(10.70)	(10.80)
Operating netback per boe [1]	($/boe)	43.97	47.51	48.54	40.81	41.28	53.13	59.97	67.77
Revenue	($M)	265,175	299,501	308,867	289,869	250,366	317,568	354,548	344,015
Net (loss) income [3]	($M)	(8,503)	92,038	32,582	80,207	(11,330)	197,796	(26,893)	13,484
Per share – basic ($)	($)	(0.10)	1.08	0.38	0.94	(0.13)	2.29	(0.30)	0.14
Per share – diluted ($)	($)	(0.10)	1.04	0.37	0.91	(0.13)	2.25	(0.30)	0.14
General and administrative	($M)	13,556	16,891	11,925	12,422	12,669	12,761	12,549	15,097
Operating EBITDA [4]	($M)	97,248	121,036	137,800	116,461	91,922	144,994	173,207	190,678
Capital expenditures [4]	($M)	69,381	82,292	74,130	154,860	131,452	134,165	76,018	93,835

(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 (loss) income 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, production has 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, this decrease is offset by 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 have 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, wage indexation, well services and maintenance activities, and changes in barrels produced affecting variable costs.

Trends in the Company's net (loss) income, attributable to equity holders of the Company, are 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, the reverse osmosis water treatment facility, the palm oil plantation, other facilities in Colombia, and the Company's investment in pipelines, all together "**Infrastructure Colombia Segment**".

The Company's Infrastructure Colombia Segment includes the following:

Asset	Description	Interest [1]	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	99.97% interest in Puerto Bahía	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

		Q1 2024	Q4 2023	Q1 2023
Operational and IFRS Results				
Volumes pumped at oil pipeline facility	(bbl/d)	246,042	252,810	225,792
Volumes throughput at port liquids facility	(bbl/d)	53,360	52,754	63,008
Volumes RORO at port general cargo facility	(Units)	12,849	15,794	30,215
Volumes at port Break Bulk Volumes	(Tons/m3)	8,481	23,230	11,034
Volumes of reverse osmosis water treated	(bwpd)	33,272	71,406	22,304
Production of fresh fruit bunch	(Tons)	5,095	3,650	5,661
Infrastructure Colombia segment income	($M)	12,552	13,220	15,989
Infrastructure Colombia segment cash flow from operating activities	($M)	643	4,243	5,635
Non IFRS Results [1]				
Adjusted Infrastructure Revenues	($M)	40,907	43,623	39,550
Adjusted Infrastructure EBITDA	($M)	25,687	27,323	27,363
Adjusted Infrastructure Cash	($M)	78,813	71,631	61,488
Adjusted Infrastructure Debt	($M)	120,024	111,423	127,164
Capital Expenditures Infrastructure Colombia Segment	($M)	4,556	9,724	1,177

[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 March 31	
($M)	**2024**	**2023**
Revenue	10,528	12,465
Costs	(8,149)	(7,136)
General and administrative expenses	(1,479)	(1,455)
Depletion, depreciation and amortization	(1,816)	(1,354)
Restructuring, severance and other costs	(426)	(103)
Infrastructure (loss) income from operations	**(1,342)**	**2,417**
Share of Income from associates - ODL	13,894	13,572
Infrastructure Colombia segment income	**12,552**	**15,989**
Infrastructure Colombia segment cash flow from operating activities	643	5,635
Capital Expenditures Infrastructure Colombia Segment [1]	4,556	1,177

[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 Adjusted Infrastructure EBITDA for the three months ended March 31, 2024, decreased by $1.7 million, compared with the same period of 2023, mainly due to a lower general cargo revenues at Puerto Bahia, lower palm oil productivity and prices, and higher operating costs due to inflationary pressures on services and wages across the segment, partially offset by higher transported volumes at ODL.

Segment capital expenditures for three months ended March 31, 2024, was $4.6 million mainly related to investments in the SAARA project and investments at Puerto Bahia including (i) general cargo terminal equipment purchases and terminal upgrading, (ii) tank maintenance, and (iii) right of way and engineering expenditure associated to the Reficar Connection Project. During the same period of 2023 capital expenditures was $1.2 million, which includes SAARA project and port facilities investments.

ODL Pipeline

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

For the three months ended March 31, 2024, ODL generated $70.8 million of EBITDA, and $39.7 million 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 March 31	
($M)	**2024**	**2023**
Revenue	86,797	77,387
FEC revenue (billed units)	7,452	6,910
Third party revenues	79,345	70,477
Costs	(11,396)	(7,496)
General administrative expenses	(4,581)	(2,778)
Depletion, depreciation and amortization	(7,926)	(5,781)
Other non-operating expense	(1,822)	(1,676)
Income tax	(21,375)	(20,880)
ODL Net Income	**39,697**	**38,776**

($M)	**March 31 2024**	**December 31 2023**
ODL debt	44,079	45,147
ODL cash and cash equivalents	172,503	131,839

The following table shows the volumes pumped per injection point:

(bbl/d)	Three months ended March 31 2024	2023
At Rubiales Station	167,378	154,817
At Jagüey and Palmeras Station	78,664	70,975
Total	**246,042**	**225,792**

The following table shows the volumes received per block:

(bbl/d)	Three months ended March 31 2024	2023
Rubiales	101,218	106,190
Quifa	28,841	27,755
CPE-6	3,513	2,263
Other blocks	97,678	72,696
Total	**231,250**	**208,904**

For the three months ended March 31, 2024, the Company recognized $13.9 million, as its share of income from ODL, which was $0.3 million higher than the same period of 2023, primarily due to the increase in crude oil volumes received and transported from the Cano Sur, Llanos 34 and Frontera blocks partially offset by an increase in its operating and G&A expenses. In March 2024, ODL declared net dividends to PIL of $54.9 million (2023: $37.0 million), and a return of capital of $7.9 million (2023: $5.2 million). During the three months ended March 31, 2024 and 2023, the Company did not received any cash from dividends or return of capital. Subsequent to the quarter closing, on April 18, 2024, PIL received cash of $31.3 million in dividends and return of capital from ODL, the remaining declared amount is expected to be received during 2024.

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 of the Cartagena Bay, and is strategically located near the Cartagena refinery operated by Reficar. The multipurpose port facility has a total area of 155 hectares. Puerto Bahia´s segment income from operations is mainly generated from service contracts in the liquids terminal with capacity of 2,672,000 barrels, and RORO and breakbulk services in the general cargo terminal.

($M)	Three months ended March 31 2024	2023
Revenue	9,705	10,844
Liquids port facility	7,102	7,194
FEC liquids port facility	2,152	1,664
Third party liquids port facility	4,950	5,530
General cargo	2,603	3,650
Costs	(6,069)	(5,117)
General and administrative expenses	(1,404)	(1,343)
Depletion, depreciation and amortization	(1,650)	(1,232)
Restructuring, severance and other costs	(426)	(103)
Puerto Bahia Operating Income	156	3,049

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

(bbl/d)	Three months ended March 31 2024	2023
FEC volumes	16,647	11,408
Third party volumes	36,713	51,600
Total	**53,360**	**63,008**

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 March 31	
		2024	2023
RORO	units [1]	12,849	30,215
	dwell time in days [2]	105	30
Break Bulk Volumes	Tons/m3 [3]	8,481	11,034
	dwell time in days [2]	—	69

[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 first quarter of 2024.
[3] Other types of cargo different from wheeled cargo.

For the three months ended March 31, 2024, Puerto Bahia had $0.2 million of income from operations (2023: $3.0 million), and $2.2 million of EBITDA (2023: $4.4 million). For the three months ended March 31, 2024 the Puerto Bahia liquids terminal revenues are relatively flat to with the same period of 2023, while general cargo revenues decreased due to lower activity and volumes of roll-on/roll-off ("RORO") and break bulk. The costs increased from $5.1 million to $6.1 million mainly due to the inflationary pressures on services and the impact of COP appreciation during the period.

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. The total estimated cost of the construction is $30.0 million. Puerto Bahia will build, operate, and maintain the connection, with a capacity of up to 84,000 barrels per day, capable of handling both imported and domestically produced crude.

Water Treatment Facility and Palm Oil Plantation

Since 2021, Frontera launched a feasibility analysis of the agricultural water reuse utilization system - SAARA, consisting in 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 removes salts from its treated water to bring it to a state suitable for use in industrial crops agricultural irrigation.

Through its wholly-owned subsidiary ProAgrollanos, the Company operates an African palm oil business located in the Municipality of Puerto Gaitan, department of Meta. Spanning across 2,960 hectares, its palm oil plantation yielded 21,218 tons of fresh fruit bunches in 2023. These crops typically exhibit an estimated productive lifespan of 30 years.

The treated water by SAARA will be reused in ProAgrollanos' agricultural activities, increasing the irrigation and targeting improving palm crop productivity of 20-25 tons per ha/year. Through this initiative, the Company aims to achieve a reduction of 105,000 tons of CO_2 per year, starting in 2026 when SAARA's full operational capacity is expected to be reached. During 2023, SAARA processed an average of 225 thousand barrels of water per day, 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:

	Three months ended March 31	
($M)	**2024**	**2023**
Revenue	823	1,621
Fresh fruit bunch from palm oil	823	1,621
SAARA	—	—
Costs	(2,080)	(2,019)
Fresh fruit bunch from palm oil	(709)	(544)
SAARA	(1,371)	(1,475)
General and administrative expenses	(75)	(112)
Depletion, depreciation and amortization	(166)	(122)
SAARA and Palm Oil Assets Operating Loss	**(1,498)**	**(632)**

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

($M)		Three months ended March 31 2024	2023
Fresh fruit bunch from palm oil (produced - sold)	(Tons)	5,095	5,661
Production per hectare	(Tons/ ha)	1.69	1.87
Palm oil fruit price	($/Ton)	160	290
Volumes of reverse osmosis water treated	(bwpd)	33,272	22,304
Volumes of water irrigated in palm oil cultivation	(bwpd)	23,613	16,162

For the three months ended March 31, 2024, fresh fruit bunch from palm oil sales was $0.8 million, a decrease of $0.8 million compared to the same period of 2023, resulting primarily from a decrease in domestic palm oil prices and field productivity. Fluctuation in fruit production volume is attributed to factors including climate conditions, agricultural practices (i.e. fertilization), market demand and community blockades in the area near to the crop.

During the three months ended March 31, 2024, volumes of treated water and palm oil cultivation irrigated were higher than the previous period, despite the temporary suspension of the plant following the conclusion of the project's pilot program on January 31, 2024. This volumetric increase was mainly due to project's performance ramp-up achieved along 2023. The last month of operation of the plant, January 2024, managed and treated approximately 100,000 bwpd.

Non-IFRS and Other Financial Measures

This MD&A contains various "**non-IFRS financial measures**" (equivalent to "**non-GAAP financial measures**", as such term is defined in NI 52-112), "**non-IFRS ratios**" (equivalent to "**non-GAAP ratios**", as such term is defined in NI 52-112), "**supplementary financial measures**" (as such term is defined in NI 52-112) and "**capital management measures**" (as such term is defined in NI 52-112), which are described in further detail below. Such measures do not have standardized IFRS definitions. The Company's determination of these non-IFRS financial measures may differ from other reporting issuers and they are therefore unlikely to be comparable to similar measures presented by other companies. Furthermore, these financial measures should not be considered in isolation or as a substitute for measures of performance or cash flows as prepared in accordance with IFRS. These financial measures do not replace or supersede any standardized measure under IFRS. Other companies in 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, 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 March 31	
($M)	2024	2023
Net loss [1]	(8,503)	(11,330)
Finance income	(1,592)	(4,301)
Finance expenses	17,270	15,221
Income tax expense	26,585	7,520
Depletion, depreciation and amortization	65,812	66,713
(Recovery) expense of asset retirement obligation	(1,042)	13,081
Expenses of impairment	1,027	16,815
Post-termination obligation	550	157
Share-based compensation	286	(499)
Restructuring, severance and other costs	1,803	1,572
Share of income from associates	(13,894)	(13,572)
Foreign exchange loss	1,097	11,760
Other loss (income)	359	(6,305)
Unrealized loss (gain) on risk management contracts	7,939	(4,825)
Non-controlling interests	(155)	(85)
Gain on repurchased 2028 Unsecured Notes	(294)	—
Operating EBITDA	**97,248**	**91,922**

[1] Refers to net loss 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 March 31	
	2024	2023
Consolidated Statements of Cash Flows		
Additions to oil and gas properties, infrastructure port, and plant and equipment	62,849	42,980
Additions to exploration and evaluation assets	2,487	88,946
Total additions in Consolidated Statements of Cash Flows	**65,336**	**131,926**
Non-cash adjustments [1]	4,045	(474)
Total Capital Expenditures	**69,381**	**131,452**
Capital Expenditures attributable to Infrastructure Colombia Segment	4,556	1,177
Capital Expenditures attributable to other segments different to Infrastructure Colombia Segment	64,825	130,275
Total Capital Expenditure	**69,381**	**131,452**

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

Adjusted Infrastructure Colombia Calculations

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

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

($M) [1]	Three months ended March 31 2024	2023
Revenue Infrastructure Colombia Segment	10,528	12,465
Revenue from ODL	86,797	77,387
Direct participation interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	30,379	27,085
Adjusted Infrastructure Revenues	**40,907**	**39,550**
Operating cost Infrastructure Colombia Segment	(8,149)	(7,136)
Operating Cost from ODL	(11,396)	(7,496)
Direct participation interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	(3,989)	(2,624)
Adjusted Infrastructure Operating Costs	**(12,138)**	**(9,760)**
General and administrative Infrastructure Colombia Segment	(1,479)	(1,455)
General and administrative from ODL	(4,581)	(2,778)
Direct participation interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	(1,603)	(972)
Adjusted Infrastructure General and Administrative	**(3,082)**	**(2,427)**

[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]	March 31 2024	December 31 2023
Cash and cash equivalents - unrestricted	154,907	159,673
Cash and cash equivalents of Non-Infrastructure Colombia Segment's	(136,470)	(134,186)
Total Cash Infrastructure Colombia Segment	18,437	25,487
Cash and cash equivalent from ODL	172,503	131,839
Direct participating interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	60,376	46,144
Adjusted Infrastructure Cash	**78,813**	**71,631**
Long-term debt	519,292	517,604
Debt of Non-Infrastructure Colombia Segment's	(414,696)	(421,982)
Total Debt	104,596	95,622
Debt from ODL	44,079	45,147
Direct participating interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	15,428	15,801
Adjusted Infrastructure Debt	**120,024**	**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 March 31	
($M)	**2024**	**2023**
Adjusted Infrastructure Revenue	40,907	39,550
Adjusted Infrastructure Operating Costs	(12,138)	(9,760)
Adjusted Infrastructure General and Administrative	(3,082)	(2,427)
Adjusted Infrastructure EBITDA	**25,687**	**27,363**

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 purchases 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 12.

Operating Netback and Oil and Gas Sales, Net of Purchases

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 effects of any trading activities and results from its 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 11.

The following is a description of each component of the Company's operating netback and how it is calculated. Oil and gas sales, net of purchases, is a non-IFRS financial measure that is calculated using oil and gas sales less the cost of volumes purchased from third parties including its transportation and refining costs. Oil and gas sales, net of purchases per boe, is a non-IFRS ratio that is calculated using 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 March 31	
	2024	**2023**
Produced crude oil and gas sales ($M) (1)	209,043	197,091
Purchased crude oil and products sales ($M)	51,285	51,316
(-) Cost of purchases ($M) (2)	(57,859)	(59,287)
Oil and gas sales, net of purchases ($M)	**202,469**	**189,120**
Sales volumes, net of purchases - (boe)	2,746,835	2,738,160
Oil and gas sales, net of purchases ($/boe)	73.71	69.07

(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 20.
(2) Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining costs.

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 March 31	
	2024	**2023**
Produced crude oil sales ($M)	207,177	193,334
Purchased crude oil and products sales ($M)	51,285	51,316
(-) Cost of purchases ($M)	(57,859)	(59,287)
Conventional natural gas sales ($M)	1,866	3,757
Oil and gas sales, net of purchases ($M) (1)	**202,469**	**189,120**
Sales volumes, net of purchases - (bbl)	2,694,482	2,607,363
Conventional natural gas sales volumes - (mcf)	298,144	745,794
Realized oil price, net of purchases ($/bbl)	74.45	71.09
Realized conventional natural gas price ($/mcf)	6.26	5.04

(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 March 31	
	2024	**2023**
Oil and gas sales, net of purchases ($M) (1)	202,469	189,120
(-) Premiums paid on oil price risk management contracts ($M)	(3,489)	(3,175)
(-) Royalties ($M)	(4,506)	(9,213)
Net sales ($M)	**194,474**	**176,732**
Sales volumes, net of purchases - (boe)	2,746,835	2,738,160
Oil and gas sales, net of purchases ($/boe)	73.71	69.07
Premiums paid on oil price risk management contracts (2)	(1.27)	(1.16)
Royalties ($/boe) (2)	(1.64)	(3.36)
Net sales realized price ($/boe)	**70.80**	**64.55**

(1) Non-IFRS financial measure.
(2) Supplementary financial measure.

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 March 31	
	2024	**2023**
Production costs (excluding energy cost) ($M)	36,839	30,387
(-) Realized gain on FX hedge attributable to production costs (excluding energy cost) ($M) (1)	(1,337)	—
Production costs (excluding energy cost), net of realized FX hedge impact ($M) (2)	35,502	30,387
Production (boe)	3,475,563	3,742,740
Production costs (excluding energy cost), net of realized FX hedge impact ($/boe)	10.21	8.12

(1) See “Gain (Loss) on Risk Management Contracts” on page 15.
(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 March 31	
	2024	**2023**
Energy costs ($M)	18,968	14,770
(-) Realized gain on FX hedge attributable to energy costs ($M) (1)	(581)	—
Energy costs, net of realized FX hedge impact ($M) (2)	18,387	14,770
Production (boe)	3,475,563	3,742,740
Energy costs, net of realized FX hedge impact ($/boe)	5.29	3.95

(1) See “Gain (Loss) on Risk Management Contracts” on page 15.
(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 March 31	
	2024	**2023**
Transportation costs ($M)	35,195	37,370
(-) Realized gain on FX hedge attributable to transportation costs ($M) (1)	(409)	—
Transportation costs, net of realized FX hedge impact ($M) (2)	34,786	37,370
Net production (boe)	3,070,613	3,336,120
Transportation costs, net of realized FX hedge impact ($/boe)	11.33	11.20

(1) See “Gain (Loss) on Risk Management Contracts” on page 15.
(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 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 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 debt of 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
- enhancing shareholder returns through share repurchases and 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 March 31, 2024, the Company had a total cash balance of $182.0 million (including $27.1 million in restricted cash), which is $8.0 million lower than December 31, 2023. For the three months ended March 31, 2024, the Company generated $65.6 million of cash from operations, which were used to fund cash outflows of $67.1 million for capital expenditures and other investing activities. For the three months ended March 31, 2024, financing activities generated net outflows of $3.1 million, respectively, mainly as a result of $5.9 million toward PetroSud Debt principal payments, $2.7 million in Common Shares purchased under the 2023 NCIB, and $1.4 million in lease payments, partially offset by $8.8 million from net proceeds from the accordion as part of the PIL Loan Facility (as defined below). In addition, the Company's net working capital(1) was improved by $68.7 million, going from a deficit of $61.9 million at year-end 2023, to a positive working capital of $6.8 million as at March 31, 2024, mainly due to the recognition of the dividends declared by ODL by $54.9 million, and a return of capital of $7.9 million from ODL, impacting the receivable in the working capital.

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 March 31, 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 March 31, 2024, the Company's restricted cash position was $27.1 million, with a decrease of $3.2 million from December 31, 2023, primarily due to the debt service reserve account used for PetroSud Debt payment and ANH abandonment funds guarantees that were replaced by letters of credit.

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

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

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 36.

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 three months ended March 31, 2024, the Company repurchased in the open market $1.5 million of its 2028 Unsecured Notes, for a cash consideration of $1.2 million including interest payable of $0.1 million. As a result, the Company recognized a gain of $0.3 million. The carrying value for the 2028 Unsecured Notes as of March 31, 2024 is $392.4 million (December 31, 2023: $393.7 million).

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 March 31, 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. ("**Frontera Holding**") and Frontera Guyana as unrestricted subsidiaries 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 March 31, 2024, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $429,556,000 as of March 31, 2024, and for the three months ended as of March 31, 2024, consolidated adjusted EBITDA of $469,113,000 and consolidated interest expense of $43,341,000.

(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 March 31 2024
Short-term and Long-term debt [1]	$	414,696
Total lease liabilities [2]		16,311
Risk management asset net		(1,451)
Consolidated Total Indebtedness		**429,556**
(-) Cash and Cash Equivalents [3]		(123,735)
(=) Net Debt	**$**	**305,821**

[1] Excludes $104.6 million of long-term debt attributable to the Unrestricted Subsidiaries.

[2] Excludes $1.5 million of lease liabilities attributable to the Unrestricted Subsidiaries.

[3] Includes unrestricted cash and cash equivalents attributable to the guarantors as of March 31, 2024, Frontera Energy Colombia AG and the Issuer (the Company) according to the Indenture.

Pipeline Investment Loan Facility

On March 27, 2023, PIL entered into a new credit agreement through which the lenders provided a $120.0 million loan facility to PIL, secured by substantially all the assets and shares of PIL, the shares of Sociedad Portuaria Puerto Bahia S.A. ("**Puerto Bahia**") held by the Company and assets related to Puerto Bahia's liquids terminal, and 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 facility, which matures in December 2027, pays semi-annually and amortizes during the term of the loan with a scheduled $45.0 million payment due upon maturity. 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 2025 Puerto Bahia Debt maturing in June 2025, which had an outstanding balance plus accrued interest of $106.2 million, pay transaction fees and expenses, and fund a 6-month debt service reserve account (for further information, refer to Note 13 of the Interim Condensed Consolidated Financial Statements for the three months ended March 31, 2023). 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 entered into an accordion facility agreement of $30.0 million with its lenders, to secure the funding for the Reficar Connection Project. On February 23, 2024, lenders disbursed $8.8 million, with additional resources expected to be disbursed in June 2024 and August 2024, each of $10.0 million. The accordion facility was recognized, net of an original issue discount of $1.2 million, primarily related to lender's fees and legal fees discounted at the disbursement.

As at March 31, 2024, the carrying value of the PIL Loan Facility was $104.6 million (December 31, 2023: $95.6 million) and the PIL Loan Facility debt service reserve account had a balance of $11.9 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 29, 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 main purpose of the Bancolombia Working Capital Loan is to fund 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 on October 29, 2024.

Concurrent with the closing of the Bancolombia Working Capital Loan, the Company repaid in full the existing Citibank working capital loan, which had an outstanding balance of $12.0 million (for further information, refer to Note 13 of the Interim Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2023).

As at March 31, 2024, the carrying value of the Bancolombia Working Capital Loan was $19.5 million (2023: $19.6 million).

[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**"). Both agreements originally had a maturity date in December 2023.

On September 15, 2023, Banco Davivienda approved an extension for the original $22.0 million loan, with an outstanding balance of $5.9 million as of December 31, 2023, extending the maturity date to June 2024. On March 11, 2024, the Company paid the outstanding balance of $5.9 million to Banco Davivienda.

On December 13, 2023, Banco Davivienda approved an extension for the original $2.8 million loan, with an outstanding balance of $2.8 million as at March 31, 2024, extending the maturity date to June 2024. The PetroSud Debt bears interest at 3-month SOFR plus 5.30%, payable quarterly.

The PetroSud Debt is subject to certain covenants that require PetroSud to maintain a financial debt to EBITDA ratio of less than or equal to 3.50:1.0 and an operating free cash flow plus the debt reserve account balance to debt service ratio that is greater than or equal to 1.20:1.0. Currently, PetroSud is in compliance with all such covenants.

Letters of Credit

The Company has various uncommitted bilateral letters of credit. As of March 31, 2024, the Company had issued letters of credit and guarantees for exploration and abandonment funds totaling $135.4 million (total credit lines of $163.8 million), without cash collateral.

CPE-6 Solar Plant Project Leasing Agreement

During the fourth quarter of 2022, the Company entered into a leasing agreement with Bancolombia to finance the construction and commissioning of a solar power plant project at the CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, for an amount equivalent to $6.7 million as at March 31, 2024, and a maturity date that is 72 months since April 3, 2024. The Solar Plant Debt bears interest equivalent to IBR +5.75%, payable monthly over the disbursed amount outstanding. As at March 31, 2024, the outstanding balance was $6.7 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, for an amount equivalent to $1.0 million as at March 31, 2024, and a maturity date that is 60 months since April 9, 2024. The BESS Project debt bears interest equivalent to IBR +5.10%, payable monthly. As at March 31, 2024, the outstanding balance was $0.8 million. The Company recognized this obligation as a lease liability.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at March 31, 2024, undiscounted by calendar year, are presented below:

As at March 31, 2024 ($M)	2024	2025	2026	2027	2028	2029 and Beyond	Total
Long term debt principal and interest	96,935	58,160	58,126	77,312	418,854	—	709,387
Lease liabilities	5,541	5,745	5,364	2,443	2,411	2,331	23,835
Total financial obligations	**102,476**	**63,905**	**63,490**	**79,755**	**421,265**	**2,331**	**733,222**
Transportation							
Ocensa P-135 ship-or-pay agreement	54,620	36,363	—	—	—	—	90,983
ODL agreements	928	—	—	—	—	—	928
Other transportation and processing commitments	11,424	12,697	12,697	569	—	—	37,387
Exploration and evaluation							
Minimum work commitments [(1)]	5,817	27,748	50,236	12,660	—	5,066	101,527
Other commitments							
Operating purchases, community obligations and others	67,810	9,608	7,474	3,221	259	2,893	91,265
Commitments energy supply	22,809	6,521	9,300	5,214	—	—	43,844
Total Commitments	**163,408**	**92,937**	**79,707**	**21,664**	**259**	**7,959**	**365,934**

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

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

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit entered into force, 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 February 21, 2024, the term of the pledge agreement was extended to September 30, 2024 with Ocensa and to October 31, 2024 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. Other than as disclosed below, no material changes have occurred regarding the matters disclosed in Note 25 - Commitments and Contingencies of the 2023 Annual Consolidated Financial Statements.

Quifa Late Delivery Volumes Claim

On September 20, 2016, Ecopetrol filed a lawsuit against the Company before the Court alleging that the Company breached the Quifa association agreement due to the alleged late delivery of the volume of crude oil produced during the period between April 3, 2011 and April 14, 2013. Consequently, Ecopetrol requested payment of $8.5 million, representing the difference between the value of the barrels of crude oil allegedly not delivered on time and the value the barrels of crude oil had on that delivery date. In addition, Ecopetrol requested the Company pay a LIBOR (six months) +3.25% from the time the delivery was due until the time of the payment.

In March 2021, the Company received notification that the Court had decided in favour of Ecopetrol and awarded $8.5 million, as adjusted by the Consumer Price Index. The Company filed an appeal against the first instance ruling on March 16, 2021.

On March 17, 2023, the Council of State issued a final ruling revoking what was decided by the Court in the first instance, ruling and stating that the statute of limitations barred Ecopetrol's judicial action. In addition, the Council of State ordered Ecopetrol to pay the Frontera Colombia's judicial costs, which amount to approximately $0.3 million. As a result, the Company recorded a reversal of a liability provision of $9.3 million recognized in 2021.

On August 28, 2023, Ecopetrol filed a constitutional action (*tutela*) in order to revoke the final decision of the Council of State that declared the statute of limitations applied to Ecopetrol's claim of the difference in the value of the barrels of crude oil as a consequence of the late delivery by the Company, in the amount of $8.5 million plus interest. The Company was linked to the proceeding as an interested third party and, on September 7, 2023, filed a statement of defense.

On September 27, 2023, the Council of State issued a first instance ruling in which it declared inadmissible the constitutional action (tutela) filed by Ecopetrol due to its lack of constitutional relevance. Ecopetrol appealed this decision and on March 18, 2024, the Council of State delivered its final ruling, dismissing the constitutional action (tutela) filed by Ecopetrol. The favorable decision for Frontera issued last year stands. The final ruling clarified that the statute of limitations did indeed apply to Ecopetrol's claim concerning the interests related to Quifa's PAP.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at May 8, 2024:

	Number
Common shares	84,482,116
Deferred share units ("**DSUs**") (1)	968,256
Restricted share units ("**RSUs**") (2)	2,545,753

(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 a 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 March 17, 2022, the Company launched a 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, 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 months ended March 31, 2024 the Company repurchased a total of 457,800 Common Shares pursuant to the 2023 NCIB. As at May 8, 2024, the Company had repurchased for cancellation a total of 949,600 Common Shares under 2023 NCIB for approximately $5.8 million with an additional 2,999,854 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 Company's 2023 NCIB program:

	Three months ended March 31
	2024
Number of Common Shares repurchased	457,800
Total amount of Common Shares repurchased ($M)	2,731
Weighted-average price per share ($) (1)	5.96

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

6. RELATED-PARTY TRANSACTIONS

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

		As at March 31, 2024 and December 31, 2023			Three Months Ended March 31
($M)		Accounts Receivable	Accounts Payable	Commitments	Purchases / Services
ODL	2024	63,536	320	928	7,452
	2023	—	3,141	2,380	6,910

The related-party transactions correspond to the ship-or-pay contract for the transportation of crude oil in Colombia for a total commitment of $0.9 million until 2024.

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 HSE, liquidity, communities and political, 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 of directors of the Company 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 includes 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 conflict in the Middle East, 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 current global crude oil price environment is being lifted mainly by the Russia-Ukraine conflict, the intervention by members of OPEC reducing oil and gas supplies and the consequences of these events on the certainty of the supply of hydrocarbons in the world. On one hand, these events are supportive of global oil prices. 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. Additionally, in 2024, management of the Company monitors any impacts of pandemics on the Company’s control environment. These impacts include remote and/or hybrid work environment, oil price environment, cyber threats, IT help desk services response time, health and safety. While there were no changes made to the Company’s ICFR that have materially affected, or are reasonably likely to materially affect, the Company’s ICFR, the Company will monitor and mitigate the risks associated with any changes to its control environment in response to pandemics.

Management of the Company has evaluated the effectiveness of the Company’s ICFR as at March 31, 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 March 31, 2024.

There have been no changes in the Company’s ICFR during the quarter ended March 31, 2024, that have materially affected, or are 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 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 March 31, 2024.

10. FURTHER DISCLOSURES

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		
Producing blocks in Colombia		**Q1 2024**	**Q4 2023**	**Q1 2023**
Heavy crude oil	(bbl/d)	20,853	19,381	19,575
Light and medium crude oil combined	(bbl/d)	9,763	10,833	14,039
Conventional natural gas	(mcf/d)	3,278	4,760	8,590
Natural gas liquids	(boe/d)	1,513	1,508	1,240
Net production Colombia	**(boe/d)**	**32,704**	**32,557**	**36,361**
Producing blocks in Ecuador				
Light and medium crude oil combined	(bbl/d)	1,039	968	707
Net production Ecuador	**(bbl/d)**	**1,039**	**968**	**707**
Total net production	**(boe/d)**	**33,743**	**33,525**	**37,068**

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
bwpd	Barrels of water per day
COP	Colombian Pesos
C$	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
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