FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

November 9, 2023

For the three and nine months ended September 30, 2023

Notice to Reader: This amended MD&A has been filed by Frontera in order to correct certain errors in the originally filed MD&A relating to the presentation of certain volumes and a detail of revenues on pages 19 and 20 under the heading "Midstream Colombia". No other changes were made to the MD&A from the version filed on SEDAR+ on November 9, 2023 and no changes were made to the financial statements for the relevant period

		Page
1	PERFORMANCE HIGHLIGHTS	2
2	GUIDANCE	6
4	FINANCIAL AND OPERATIONAL RESULTS	6
5	LIQUIDITY AND CAPITAL RESOURCES	27
6	OUTSTANDING SHARE DATA	34
7	RELATED-PARTY TRANSACTIONS	34
8	RISKS AND UNCERTAINTIES	35
9	ACCOUNTING POLICIES	36
10	INTERNAL CONTROL	36
11	FURTHER DISCLOSURES	37

*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 related investments in both upstream and midstream 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 – 3 Avenue SW, Calgary, Alberta, Canada, T2P 0B4.*

Legal Notice – Forward-Looking Information

*This Management Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Consolidated Financial Statements and related notes for the three and nine months ended September 30, 2023 and 2022 ("**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 22.*

*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 the COVID-19 pandemic, actions of the Organization of Petroleum Exporting Countries ("**OPEC+**"), the impact of the Russia-Ukraine conflict and the Israel-Palestine conflict, 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, our 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 the COVID-19 pandemic, including the status of the pandemic and future waves and any associated policies around current business restrictions; 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; the duration and spread of the COVID-19 pandemic and its severity, the success of the Company's program to manage COVID-19; the Russia-Ukraine conflict and the Israel-Palestine conflict; uncertainties associated with estimating and establishing oil and natural gas reserves and resources; liabilities inherent with the exploration, development, exploitation and reclamation of oil and natural gas; uncertainty of estimates of capital and operating costs, production estimates and estimated economic return; increases or changes to transportation costs; expectations regarding the Company's ability to raise capital and to continually add reserves through acquisition and development; the Company's ability to access additional financing; the ability of the Company to maintain its credit ratings; the ability of the Company to: meet its financial obligations and minimum commitments, fund capital expenditures and comply with covenants contained in the agreements that govern indebtedness; political developments in the countries where the Company operates; the uncertainties involved in interpreting drilling results and other geological data; geological, technical, drilling and processing problems; the effectiveness of our restructuring plan; timing on receipt of government approvals; fluctuations in foreign exchange or interest rates and stock market volatility.

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

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

1. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q3 2023	Q2 2023	Q3 2022	Nine months ended September 30 2023	Nine months ended September 30 2022
Operational Results						
Heavy crude oil production [1]	(bbl/d)	24,097	24,051	20,945	23,480	21,203
Light and medium crude oil combined production [1]	(bbl/d)	13,964	15,188	17,428	15,214	17,342
Total crude oil production	(bbl/d)	38,061	39,239	38,373	38,694	38,545
Conventional natural gas production [1]	(mcf/d)	5,250	5,626	9,969	6,475	9,958
Natural gas liquids production [1]	(boe/d)	1,820	1,823	911	1,647	946
Total production [2]	(boe/d) [3]	40,802	42,049	41,033	41,477	41,238
Total inventory balance	(bbl)	1,330,418	1,434,508	1,137,913	1,330,418	1,137,913
Brent price reference	($/bbl)	85.92	77.73	97.70	81.94	104.94
Oil and gas sales, net of purchases [4] [5]	($/boe)	78.48	67.91	90.40	71.97	94.49
Premiums paid on oil price risk management contracts [6]	($/boe)	(0.59)	(0.80)	(1.30)	(0.83)	(1.18)
Royalties [6]	($/boe)	(3.76)	(3.02)	(7.23)	(3.38)	(8.46)
Net sales realized price [4] [5]	($/boe)	74.13	64.09	81.87	67.76	84.85
Production costs, net of realized FX hedge impact [4][5]	($/boe)	(13.86)	(12.39)	(11.20)	(12.77)	(12.34)
Transportation costs, net of realized FX hedge impact [4][5]	($/boe)	(11.73)	(10.89)	(10.70)	(11.27)	(10.40)
Operating netback per boe [4]	($/boe)	48.54	40.81	59.97	43.72	62.11
Financial Results						
Oil & gas sales, net of purchases [7]	($M)	254,805	221,218	304,899	665,143	844,680
Premiums paid on oil price risk management contracts	($M)	(1,930)	(2,600)	(4,393)	(7,705)	(10,551)
Royalties	($M)	(12,216)	(9,837)	(24,371)	(31,266)	(75,633)
Net sales [7]	($M)	240,659	208,781	276,135	626,172	758,496
Net income (loss) [8]	($M)	32,582	80,207	(26,893)	101,459	88,819
Per share – basic	($)	0.38	0.94	(0.30)	1.19	0.96
Per share – diluted	($)	0.37	0.92	(0.30)	1.16	0.94
General and administrative	($M)	11,925	12,422	12,549	37,016	42,302
Outstanding Common Shares	Number of Shares	85,431,716	85,188,573	86,575,175	85,431,716	86,575,175
Operating EBITDA [7]	($M)	137,800	116,461	173,207	346,183	496,883
Cash provided by operating activities	($M)	153,957	183,560	120,804	338,362	482,167
Capital expenditures [7]	($M)	74,130	154,860	76,018	360,442	283,398
Cash and cash equivalents – unrestricted	($M)	189,190	180,294	253,550	189,190	253,550
Restricted cash short and long-term [9]	($M)	32,048	33,485	55,552	32,048	55,552
Total cash [9]	($M)	221,238	213,779	309,102	221,238	309,102
Total debt and lease liabilities [9]	($M)	525,517	532,273	533,077	525,517	533,077
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [10]	($M)	409,853	415,395	412,926	409,853	412,926
Net debt (excluding Unrestricted Subsidiaries) [10]	($M)	271,508	286,675	205,625	271,508	205,625

[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 37.
[3] Boe has been expressed using the 5.7 to 1 Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy. Refer to the "Further Disclosures - Boe Conversion" section on page 37.
[4] Non-IFRS ratio (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 22.
[5] 2022 prior period figures are different compared with those previously reported as a result of the exclusion of Promotora Agricola de los Llanos S.A. ("**ProAgrollanos**") revenues and, production and transportation costs.
[6] Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
[7] 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 22.
[8] Net income (loss) attributable to equity holders of the Company.
[9] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
[10] "**Unrestricted Subsidiaries**" include CGX Energy Inc.("**CGX**"), listed on the TSX Venture Exchange under the trading symbol "OYL", Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. ("**PIL**"), Frontera BIC Holding Ltd. and Frontera Bahía Holding Ltd. ("**Frontera Bahia**"), including its subsidiary 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 27.

Performance Highlights

Third Quarter 2023

Driven in part by a 16% increase in its net sales realized price, Frontera generated operating EBITDA of $137.8 million in the third quarter of 2023, and increased its operating netback by 19% compared to the prior quarter. For the nine months ended September 30, 2023, Frontera has generated almost $350 million of operating EBITDA. Year to date production and EBITDA to the end of the third quarter are within the Company’s guidance ranges at $80/bbl average Brent prices for the year.

Colombia and Ecuador Upstream

Frontera delivered average daily production of 40,802 boe/d (consisting of 24,097 bbl/d of heavy crude oil, 13,964 bbl/d of light and medium crude oil combined, 5,250 mcf/d of conventional natural gas and 1,820 boe/d of natural gas liquids), increasing its heavy oil production and natural gas liquids production 15% and 100%, respectively, compared with the same quarter last year. The company also delivered record quarterly average production of 5,803 boe/d at CPE-6, up 13% compared to the prior quarter through development drilling, installation of new flow lines, and expanded facilities which will double water-handling capacity on the block by the end of 2023. Subsequent to the quarter, the Company achieved record daily production of 6,435 bbl/d at CPE-6.

The Company remains on track to deliver its 2023 production guidance of 40,000 - 43,000 boe/d and, year to date to the end of September 2023, has invested $360.4 million in capital expenditures or, almost 80% of its 2023 capital guidance The Company’s balance sheet is strong. The Company reduced its G&A by 4% quarter over quarter and increased its total cash position, including restricted cash, by 3% to $221.2. During third quarter, the Company successfully collected $80.0 million of VAT and income tax receivable, and obtained a cash provided by operating activities of $154.0 million, increasing 27% compared with the same period of 2022.

Operationally, in the third quarter of 2023, the Company drilled 14 development wells, one injector well and completed well services at 21 others. Year to date, the Company has drilled 50 development wells and 2 injector wells and completed workover services at 61 others.

The Company’s current water handling capacity in Quifa is approximately 1.6 million bwpd. During the third quarter, Frontera continued with its recommissioning efforts supporting SAARA, its reverse osmosis water treatment facility with an estimated 1 million bwpd nameplate capacity. As of October 2023, the plant had processed 16.3 million barrels of water as part of its recommissioning program, providing irrigation source water to the Company's nearby ProAgrollanos palm oil plantation. The Company is actively engaged in discussions with Ecopetrol to permanently bring the SAARA facility online under terms mutually acceptable to both parties.

On the Perico block in Ecuador (Frontera 50% W.I. and operator), the Company drilled the Perico Centro-1 (formerly Jandiayacu-1) well, discovering 19.5 feet of net pay in the Lower U sand with oil found in three intervals and initial tests delivering average production of approximately 800 bbl/d, 28-degree API medium crude oil with 1% BSW. Clean-up activities are underway. The Company believes that the Upper Hollin presents additional exploration or production opportunity. With the completion of drilling activities at the Perico Centro-1 well, the Company has satisfied its four-well exploration commitment on the block.

The Company also spudded and completed the Yin-2 appraisal well in the third quarter, discovering 48 feet of net pay in the Lower U sand and 24 feet of net pay in the Hollin main formation, with initial production rates of approximately 1,200 bbl/d of 30.5-degree API crude oil. In addition, the Perico Norte A4 well was spudded on October 8, 2023, reached a total depth of 11,433 feet (3,485 meters) and was completed on November 4, 2023 with initial production rates of approximately 1,200 bbl/d of 29.4-degree API crude oil with 5% BSW.

The Company continues to conduct long-term testing at the Jandaya-1, Tui-1 and Yin-1 exploration wells, as it prepares environmental impact assessments in advance of obtaining production environmental licenses.

Midstream Colombia

For the three months ended September 30, 2023, income from the Company’s Midstream Colombia Segment was $17.3 million, compared with $15.2 million in the third quarter of 2022. For the three months ended September 30, 2023, the Puerto Bahia liquids terminal revenues was $7.8 million compared with $7.7 million in the same period of 2022, the liquids terminal revenues during the third quarter of 2023, represents 60% of Puerto Bahia revenues. On the general cargo bussines revenues increased by 20% compared with the same period in 2022, primarily driven by $1.2 million of additional revenues from the shore base operation.

For the three and nine months ended September 30, 2023, ODL generated $39.2 million and $119.0 million of net income, respectively. ODL total volumes pumped were 251,988 bbl/d during the third quarter, up 17% compared to the quarter of 2022 driven by stronger crude oil volumes from the Cano Sur block. ODL results are recorded through the equity method in the Company's Interim Financial Statements as “Share of Income from associates”.

Preconstruction activities are underway for Puerto Bahia’s 6.8-kilometre, 18-inch bi-directional hydrocarbon flow line with Refineria de Cartagena S.A.S. (“**Reficar**”). Once in service, the connection shall enable the continuous transport of crude oil and other hydrocarbons between Puerto Bahía's port facility and the Cartagena Refinery.

Since the announcement in August 2023, the connection project has already achieved milestones in various key areas including technical, environmental and social matters, financing and procurement.

Guyana Offshore Exploration

Frontera, along with its joint venture (the “Joint Venture”) partner, CGX, announced that the Joint Venture has discovered a total of 114 feet (35 meters) of net pay at the Wei-1 well and a total net pay of 342 feet (104 meters) discovered to date on the North Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana.

The Joint Venture believes that the rock quality discovered in the Maastrichtian horizon in the Wei-1 well is analogous to that reported in the Liza Discovery on Stabroek block (see “Analogous Information”). Results further demonstrate the potential for a standalone shallow oil resource development across the Corentyne block.

Based on this data acquisition program and additional information provided through the independent laboratory analysis process, the Joint Venture reported in the Maastrichtian, Wei-1 test results and analysis confirm 13 feet (4 meters) of net pay in high quality sandstone reservoir. Fluid samples retrieved from the Maastrichtian and log analysis confirm the presence of sweet medium crude oil with a gas-oil ratio (GOR) of approximate 400 standard cubic feet per barrel.

In the Campanian, petrophysical analysis confirms 61 feet (19 meters) of net pay almost completely contained in one contiguous sand body with good porosity and moveable oil. Oil sampled during MDT testing as well as samples analyzed downhole confirm the presence of light crude oil in the Campanian. In the Santonian, petrophysical analysis confirms 40 feet (12 meters) of net pay in blocky sands with indications of oil in core samples.

Current interpretation of the Campanian and Santonian horizons show lower permeability and natural flow than the high-quality Maastrichtian; however, the Joint Venture believes these horizons may offer additional upside potential in the future.

In parallel with the third-party laboratory confirmation of our significant light oil and sweet medium crude discovery at Wei-1, the Joint Venture, with support from Houlihan Lokey, is reviewing strategic options for its potentially transformational Guyana exploration business, the Corentyne block, including a potential farm down, as it progresses its efforts to maximize value from its potentially transformational investments in Guyana.

ESG Initiatives

Importantly, the Company continues to deliver on its ESG goals. Through September 2023, Frontera achieved a Total Recordable Incident Rate (TRIR) of 0.49, the best safety performance in Company history and below its 2023 TRIR objective of 0.74. During the third quarter, Frontera protected and preserved 1,367 hectares of land thanks to a land purchase in the Serranía de Manacacías Park, Entrerríos, reforestation plantings and sustainable use projects, exceeding the Company’s goal of 1,000 hectares and totaling 5,994 hectares preserved.

As of September 2023, the Company has recycle 41.4% of the water use in its operation and has offset 33% of its 2023 Colombian emissions through the purchase of carbon credits. Additionally, the Company continues to focus on bridging diversity, inclusion, and gender equity gaps. During the quarter, Frontera hired six locally trained community women as well operators through its oil and gas technical program called - Crece con Frontera.

As of September 2023, Frontera has invested $2.1 million in 161 social projects, benefiting more than 33,000 people in Colombia, Ecuador and Peru. The Company purchased $50.9 million from local suppliers and will accomplish its goal of purchasing $55 million locally in 2023.

Shareholder Initiatives

Frontera also announced that the Company intends to file with the TSX a notice of intention to commence a normal course issuer bid for its Common Shares (the "**2023 NCIB**"). If accepted by the TSX, the Company would be permitted under the 2023 NCIB to purchase, during a 12-month period, up to 3,872,358 Common Shares, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules). Frontera believes that, from time to time, the market price of its Common Shares may not fully reflect the underlying value of its business and future prospects and financial position. In such circumstances, Frontera may purchase for cancellation outstanding Common Shares, thereby benefiting all shareholders by increasing the underlying value of the remaining Common Shares. The Company remains committed to returning capital to shareholders and continues to consider future shareholder value enhancement initiatives opportunities.

Restructuring Plan

Subsequent to the quarter, the board of directors of the Company approved a restructuring plan that is designed to improve operational efficiencies, reduce operating costs and better align the Company's workforce with current business needs, top strategic priorities and key growth opportunities (collectively, the "**Restructuring Plan**"). The Restructuring Plan includes reduction of the Company's workforce by approximately 16%.

Financials and Operational Results

- Production averaged 40,802 boe/d in the third quarter of 2023 (consisting of 24,097 bbl/d of heavy crude oil, 13,964 bbl/d of light and medium crude oil combined, 5,250 mcf/d of conventional natural gas and 1,820 boe/d of natural gas liquids), compared to 42,049 boe/d in the prior quarter (consisting of 24,051 bbl/d of heavy crude oil, 15,188 bbl/d of light and medium crude oil combined, 5,626 mcf/d of conventional natural gas and 1,823 boe/d of natural gas liquids), and compared to 41,033 boe/d in the third quarter of 2022 (consisting of 20,945 bbl/d of heavy crude oil, 17,428 bbl/d of light and medium crude oil combined, 9,969 mcf/d of conventional natural gas and 911 boe/d of natural gas liquids).

- Cash provided by operating activities was $154.0 million in the third quarter of 2023, compared with $183.6 million in the prior quarter, and $120.8 million in the third quarter of 2022. The Company reported a total cash position of $221.2 million, including $32.0 million of restricted cash, as at September 30, 2023, compared with a total cash position of $309.1 million, including $55.6 million of restricted cash, as at September 30, 2022.

- The Company recorded a net income(1) of $32.6 million ($0.37/share(2)) in the third quarter of 2023, compared with net income of $80.2 million ($0.92/share(2)) in the prior quarter and net loss(1) of $26.9 million ($0.30/share(2)) in the third quarter of 2022.

- Capital expenditures were $74.1 million in the third quarter of 2023, compared with $154.9 million in the prior quarter and $76.0 million in the third quarter of 2022.

- Operating EBITDA was $137.8 million in the third quarter of 2023, compared with $116.5 million in the prior quarter and $173.2 million in the third quarter of 2022.

- Operating netback was $48.54/boe in the third quarter of 2023, compared with $40.81/boe in the prior quarter and $59.97/boe in the third quarter of 2022.

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

2. GUIDANCE

The following table reports the Company´s actual results for the nine months ended September 30, 2023, against the full year 2023 guidance metrics as released on February 1, 2023.

		2023	
		Guidance	Actual
Average Daily Production[(1)]	boe/d	40,000 - 43,000	41,477
Production Costs, net of realized FX hedge impact[(2)]	$/boe	12.50 - 13.50	12.77
Transportation Costs, net of realized FX hedge impact[(3)]	$/boe	10.50 - 11.50	11.27
Operating EBITDA[(4)] at $80/bbl[(5)]	$MM	425 - 475	346.2
Operating EBITDA[(4)] at $85/bbl[(5)]	$MM	475 - 525	
Development Drilling	$MM	110 - 130	98.7
Development Facilities	$MM	75 - 85	54.1
Colombia and Ecuador Exploration	$MM	50 - 60	38.1
Colombia Infrastructure[(6)]	$MM	5 - 10	3.5
Other[(7)]	$MM	25 - 30	9.2
Total Colombia and Ecuador Capital Expenditures	$MM	265 - 315	203.6
Guyana Exploration and Infrastructure[(8)]	$MM	155 - 160	156.8
Total Capital Expenditure[(9)]	$MM	415 - 480	360.4

(1) The Company's 2023 average production guidance range does not include in-kind royalties, operational consumption, quality volumetric compensation or potential production from successful exploration activities planned in 2023.
(2) Supplementary financial measure (as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures". Per-barrel metric on a share before royalties basis; excludes costs related to ProAgrollanos.
(3) Supplementary financial measure (as defined in NI 52-112). Refer to the “Non-IFRS and Other Financial Measures". Calculated using net production after royalties.
(4) 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”.
(5) Current Guidance Operating EBITDA calculated at Brent $80/bbl and $85/bbl,respectively, and COP/USD exchange rate of 4600:1. Unexpected foreign exchange changes can impact actual results. See “Risk and Uncertainties”
(6) Colombian Infrastructure refers to Puerto Bahia capital expenditures.
(7) Other includes the CPE-6 solar plant project, investment in equipment covered by insurance proceeds, investment in new technologies and HSEQ.
(8) Guidance for Capital Expenditure of Guyana Exploration was updated on November 9, 2023. Total costs associated for the Wei-1 well are now estimated to be within $185-190 million following the successful implementation of several initiatives.
(9) Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). See "Non-IFRS Financial and Other Measures." Capital expenditures excludes decommissioning expenses (approximately $14 million).

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company’s operations in Colombia and Ecuador. Refer to the “**Further Disclosures**” section on page 37 for details of the Company’s net production.

		Production				
					Nine months ended September 30	
Producing blocks in Colombia		**Q3 2023**	**Q2 2023**	**Q3 2022**	**2023**	**2022**
Heavy crude oil	(bbl/d)	24,097	24,051	20,945	23,480	21,203
Light and medium crude oil combined	(bbl/d)	13,312	14,575	16,224	14,459	16,641
Conventional natural gas	(mcf/d)	5,250	5,626	9,969	6,475	9,958
Natural gas liquids	(boe/d)	1,820	1,823	911	1,647	946
Total production Colombia	**(boe/d)**	**40,150**	**41,436**	**39,829**	**40,722**	**40,537**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	652	613	1,204	755	701
Total production Ecuador	**(bbl/d)**	**652**	**613**	**1,204**	**755**	**701**
Total production	**(boe/d)**	**40,802**	**42,049**	**41,033**	**41,477**	**41,238**

Colombia

For the three months ended September 30, 2023, production in Colombia decreased by 1,286 boe/d compared to the prior quarter. Lower production was mainly the result of a reduction in production of the Company's light and medium crude oil combined driven in part by the relinquishment of the Neiva block (which produced approximately 587 boe/d) to Ecopetrol following the completion of the block's production contract during the second quarter of 2023.

Compared to the three and nine months ended September 30, 2022, production increased by 321 boe/d and 185 boe/d, respectively, mainly due to: (i) heavy crude oil increases by 15% and 11%, respectively, due to production increases in the Cajua, Quifa and CPE-6 blocks as a result of the successful development drilling campaign, increases in water handling capacity through SAARA project in Quifa block, new facilities in CPE-6 block, and the reactivation of the Sabanero block on July 1, 2022 (ii) increased production of natural gas liquids by 100% and 74%, respectively, in the VIM-1 block as a result of the development of the facilities in the block. Increases were partially offset by lower production in light and medium crude oil of 18% and 13%, respectively, and conventional natural gas by 47% and 35%, primarily due to natural decline, the finalization of the Neiva block production contract and the relinquishment of La Creciente block.

Ecuador

Production in Ecuador for the three and nine months ended September 30, 2023, increased to 652 bbl/d and 755 bbl/d, respectively, of light and medium crude oil combined, compared to 613 bbl/d in the prior quarter, and 701 bbl/d in the nine months ended September 30, 2022; the increase was mainly due to the completion of two exploration wells, Yin 2 and Perico Centro 1 (formerly Jandiayacu-1) and the successful Jandaya-1 well stimulation, at the Perico block, partially offset by the interruption of production in the Espejo block (Frontera 50% W.I., and non-operator). In comparison to the third quarter of 2022, production decreased from 1,204 bbl/d mainly due to BSW increases in the Perico block. On October, 2023, the Company drilled a third exploration well, Perico Norte 4, which in addition to the two exploration wells drilled during the third quarter, will stabilize production in Ecuador over 1,100 bbl/d for the end of 2023.

Production Reconciled to Sales Volumes

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

					Nine months ended September 30	
		Q3 2023	Q2 2023	Q3 2022	2023	2022
Production	(boe/d)	**40,802**	**42,049**	**41,033**	**41,477**	**41,238**
Royalties in-kind Colombia	(boe/d)	(4,093)	(4,163)	(5,236)	(4,160)	(5,074)
Royalties in-kind Ecuador [1]	(boe/d)	(192)	(180)	(485)	(223)	(283)
Net production	(boe/d)	**36,517**	**37,706**	**35,312**	**37,094**	**35,881**
Oil inventory draw (build)	(boe/d)	1,131	1,941	3,207	(336)	(1,178)
Overlift (settlement)	(boe/d)	—	2	17	(1)	7
Volumes purchased	(boe/d)	6,246	7,691	6,841	7,302	4,982
Other inventory movements [2]	(boe/d)	(1,841)	(2,471)	(2,082)	(2,383)	(1,876)
Sales volumes	(boe/d)	**42,053**	**44,869**	**43,295**	**41,676**	**37,816**
Sale of volumes purchased	(boe/d)	(6,764)	(9,070)	(6,635)	(7,821)	(5,072)
Sales volumes, net of purchases	(boe/d)	**35,289**	**35,799**	**36,660**	**33,855**	**32,744**
Oil sales volumes	(bbl/d)	34,206	34,827	34,838	32,687	30,962
Conventional natural gas sales volumes	(mcf/d)	6,173	5,540	10,385	6,658	10,158
Total oil and conventional natural gas sales volumes, net of purchases	**(boe/d)**	**35,289**	**35,799**	**36,660**	**33,855**	**32,744**
Inventory balance						
Colombia	(bbl)	812,797	881,758	590,984	812,797	590,984
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	37,421	72,550	66,729	37,421	66,729
Inventory ending balance	**(bbl)**	**1,330,418**	**1,434,508**	**1,137,913**	**1,330,418**	**1,137,913**

[1] The Company reports the share of production retained by the government of Ecuador as royalties paid in-kind.
[2] Mainly corresponds to operational consumption and quality volumetric compensation.

Sales volumes, net of purchases, for the three months ended September 30, 2023, decreased by 1% compared with the prior quarter and 4% compared with the same period of 2022. The decrease was mainly due to lower volumes of conventional natural gas sold. For the nine months ended September 30, 2023, sales volumes net of purchases, increased by 3%, compared with the same period of 2022, as a result of an increase of heavy oil production and natural gas liquids production from VIM1 block.

Colombia Royalties PAP

The Company makes high price clause participation ("**PAP**") payments to Ecopetrol S.A. ("**Ecopetrol**") and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo, Arrendajo and CPE-6 blocks. Until last year (2022), the PAP was paid in cash for all blocks except for those relating to the Quifa block, which were paid using in-kind volumes from production. However, during the year 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) blocks.

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

					Nine months ended September 30	
		Q3 2023	Q2 2023	Q3 2022	2023	2022
PAP in cash	(bbl/d)	788	733	2,238	771	2,265
PAP in kind	(bbl/d)	1,791	2,303	3,150	1,852	2,851
PAP	**(bbl/d)**	**2,579**	**3,036**	**5,388**	**2,623**	**5,116**
% Production		**6.3 %**	**7.2 %**	**13.1 %**	**6.3 %**	**12.4 %**

For the three and nine months ended September 30, 2023, the total PAP decreased compared with the same periods of 2022, mainly due to a lower WTI oil benchmark price. For the three and nine months ended September 30, 2023, PAP in cash decreased compared with the same periods of 2022, mainly due to a change in the payment method required by ANH as mentioned above and lower WTI oil benchmark price, and compared with the prior quarter, PAP in cash increased mainly due to higher WTI oil benchmark price. For the three and nine months ended September 30, 2023, PAP in kind decreased compared to the same periods of 2022, mainly due to lower WTI oil benchmark price partially offset by the change in the payment method required by ANH. Compared with the prior quarter PAP in kind decreased mainly due to lower volumes delivered from the Quifa block.

Realized and Reference Prices

					Nine months ended September 30	
		Q3 2023	Q2 2023	Q3 2022	2023	2022
Reference price						
Brent	($/bbl)	85.92	77.73	97.70	81.94	104.94
Average realized prices						
Realized oil price, net of purchases	($/bbl)	80.08	68.88	93.76	73.49	98.45
Realized conventional natural gas price	($/mcf)	4.91	5.65	4.61	5.17	4.50
Net sales realized price						
Oil and gas sales, net of purchases (1)	($/boe)	78.48	67.91	90.40	71.97	94.49
Premiums paid on oil price risk management contracts(2) (3)	($/boe)	(0.59)	(0.80)	(1.30)	(0.83)	(1.18)
Royalties (2)	($/boe)	(3.76)	(3.02)	(7.23)	(3.38)	(8.46)
Net sales realized price (1)	**($/boe)**	**74.13**	**64.09**	**81.87**	**67.76**	**84.85**

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(3) Includes put premiums paid for the position expired during the period.

The average Brent benchmark oil price during the three and nine months ended September 30, 2023, decreased by 12% and 22%, respectively, compared to the same periods of 2022. In comparison to the second quarter of 2023, the average Brent benchmark oil price increased by 11%. The decrease in crude oil prices during 2023 compared with the same period of 2022, was mainly due to: (i) a potential recession in the main global economies and a decoupling of US/European and Chinese economies which negatively impacted market expectations regarding worldwide economies and expectations for future crude oil price increases, and (ii) the impact of US/European sanctions on Russia's crude oil production being lower than market analysts' assumptions. Compared to the second quarter of 2023, the market has shown an improvement as OPEC+ has announced its 3 million barrels per day production cut until December, and China has started to show some stability in its economy.

For the three and nine months ended September 30, 2023, the Company's net sales realized price decreased 9% and 20%, compared to the same periods of 2022, respectively. The decrease in the Company's net sales realized price was driven by the decrease in the Brent benchmark oil price and higher differential prices, partially offset by lower royalties. In comparison to the previous quarter, the Company's net sales realized price increased from $64.09/boe to $74.13/boe, mainly due to the increase in the Brent benchmark oil price, better oil differential prices, and lower premiums paid on oil price risk management contracts, partially offset by higher royalties.

Operating Netback

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

	Q3 2023		Q2 2023		Q3 2022	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price [1]	240,659	74.13	208,781	64.09	276,135	81.87
Production costs, net of realized FX hedge impact [1][2][3]	(52,015)	(13.86)	(47,406)	(12.39)	(42,263)	(11.20)
Transportation costs, net of realized FX hedge impact [1][2][4]	(39,422)	(11.73)	(37,363)	(10.89)	(34,746)	(10.70)
Operating Netback [1] [2]	**149,222**	**48.54**	**124,012**	**40.81**	**199,126**	**59.97**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases [5]		35,289		35,799		36,660
Production [6]		40,802		42,049		41,033
Net production [7]		36,517		37,706		35,312

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(3) Includes $2.9 million, $6.2 million and $Nil of realized FX hedge gain attributable to production costs for the third quarter of 2023, second quarter of 2023, and the third quarter of 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 14.
(4) Includes $0.7 million, $1.8 million and $Nil of realized FX hedge gain attributable to transportation costs for the third quarter of 2023, second quarter of 2023, and the third quarter of 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 14.
(5) Sales volumes, net of purchases, exclude sales of third-party volumes.
(6) Refer to the "Production" section on page 6.
(7) Refer to the "Further Disclosures" section on page 37.

The Company's operating netback for the third quarter of 2023 was $48.54/boe, compared to $59.97/boe in the same quarter of 2022. The decrease was a result of lower net sales realized prices, higher production costs, net of realized FX hedge impact, resulting from higher electricity costs and fuel consumption, partially offset by lower well services activity costs. In addition, transportation costs, net of realized FX hedge impact increased mainly due to the annual increase of the transportation tariffs.

In comparison to the second quarter of 2023, the Company's operating netback increased from $40.81/boe to $48.54/boe, representing an increase of 19%, mainly due to a higher realized price, partially offset higher production costs, net of realized FX hedge impact, resulting from higher technical assistance, electricity costs and fuel consumption partially offset by lower well services activity costs. In addition transportation costs, net of realized FX hedge impact increased mainly due to foreign exchange impacts.

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

	Nine months ended September 30			
	2023		2022	
	$M	($/boe)	$M	($/boe)
Net sales realized price [(1)]	626,172	67.76	758,496	84.85
Production costs, net of realized FX hedge impact [(1)(2)(3)]	(144,578)	(12.77)	(138,937)	(12.34)
Transportation costs, net of realized FX hedge impact [(1)(2)(4)]	(114,155)	(11.27)	(101,894)	(10.40)
Operating Netback [(1) (2)]	**367,439**	**43.72**	**517,665**	**62.11**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases [(5)]		33,855		32,744
Production [(6)]		41,477		41,238
Net production [(7)]		37,094		35,880

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(2) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(3) Includes $9.1 million and $Nil of realized FX hedge gain attributable to production costs for the nine months ended September 30, 2023 and 2022, respectively. See "Gain (Loss) on Risk Management Contracts" on page 14.
(4) Includes $2.5 million and $Nil of realized FX hedge gain attributable to transportation costs for the nine months ended September 30, 2023 and 2022, respectively.
(5) Sales volumes, net of purchases, exclude sales of third-party volumes. See "Gain (Loss) on Risk Management Contracts" on page 14.
(6) Refer to the "Production" section on page 6.
(7) Refer to the "Further Disclosures" section on page 37.

Operating netback for the nine months ended September 30, 2023, decreased by 30% from $62.11/boe to $43.72/boe, compared to the same period of 2022. The decrease was as a result of the same reasons for three-month variation with respect to the previous year explained above.

Sales

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Oil and gas sales, net of purchases [(1)]	254,805	304,899	665,143	844,680
Premiums paid on oil price risk management contracts [(2)]	(1,930)	(4,393)	(7,705)	(10,551)
Royalties	(12,216)	(24,371)	(31,266)	(75,633)
Net sales [(1)]	**240,659**	**276,135**	**626,172**	**758,496**
Net sales realized price ($/boe) [(3)]	74.13	81.87	67.76	84.85

(1) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(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 22.

Oil and gas sales, net of purchases, decreased by $50.1 million and $179.5 million for the three and nine months ended September 30, 2023, respectively, compared to the same periods of 2022, mainly due to lower Brent benchmark oil prices and higher price differentials (Refer to the "Realized and Reference Prices" section on page 8 for further details on changes in prices).

Net sales for the three and nine months ended September 30, 2023, decreased by $35.5 million and $132.3 million, respectively, compared with the same periods of 2022. The following table describes the various factors that impacted net sales:

	Three months ended September 30	Nine months ended September 30
($M)	**2023-2022**	**2023-2022**
Net sales for the period ended September 30, 2022	276,135	758,496
Decrease due to 13% lower oil and gas price (YTD 24% lower)	(40,206)	(201,344)
Decrease (Increase) due to 4% lower produced volumes sold (YTD 3% higher)	(9,888)	21,807
Decrease in premiums paid on oil price risk management contracts	2,463	2,846
Decrease in royalties	12,155	44,367
Net sales for the period ended September 30, 2023	**240,659**	**626,172**

Oil and Gas Operating Costs

($M)	Three months ended September 30		Nine months ended September 30	
	2023	2022	2023	2022
Production costs	54,942	42,263	153,714	138,937
Transportation costs	40,166	34,746	116,666	101,894
Post-termination obligation	1,377	—	7,654	7,070
Inventory valuation	1,178	15,682	(7,436)	(10,509)
Total oil and gas operating costs	**97,663**	**92,691**	**270,598**	**237,392**

Total oil and gas operating costs increased by 5% and 14%, respectively, for the three and nine months ended September 30, 2023, compared to the same periods of 2022. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs for the three and nine months ended September 30, 2023, increased by 30% and 11%, respectively, compared with the same periods of 2022, primarily due to higher electricity costs, fuel consumption and maintenance, partially offset by lower well services activity costs.
- For the three and nine months ended September 30, 2023, transportation costs increased by 16% and 14%, respectively, compared to the same periods of 2022, primarily due to the annual increase of the transportation tariffs and higher volumes produced and transported in Colombia.
- Post-termination obligations for the three and nine months ended September 30, 2023, includes environmental commitments and operational costs related to the relinquishment of the Rio Ariari, Neiva, Orito, Mapache, Guaduas, and La Creciente blocks, and the Arauco and Espadarte fields, in Colombia, while during the same period of 2022, the Company recognized post-termination obligations related to non-recurring cleaning activities to be executed in Block 192, in Peru.
- Inventory valuation for the three months ended September 30, 2023, decreased by $14.5 million, compared with the same period of 2022, mainly due to lower inventory draw-down in 2023, while during the nine months ended September 30, 2023, it increased by $3.1 million, compared with the same period of 2022, mainly as a result of lower inventory build-up in 2023.

Cost of Purchases

($M)	Three months ended September 30		Nine months ended September 30	
	2023	2022	2023	2022
Cost of purchases (1)	54,555	63,478	180,444	152,394

(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 22.

Cost of purchases corresponds 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 September 30, 2023, the cost of purchases including the transportation and processing fees for purchased volumes sold decreased $8.9 million compared with the same period of 2022, mainly due to lower Brent benchmark oil prices.

For the nine months ended September 30, 2023, the cost of purchases, including the transportation and processing fees for purchased volumes sold increased $28.1 million, due to additional volumes acquired as a result of higher dilution and energy consumption requirements driven by an increase of heavy crude oil production, partially offset by lower Brent benchmark oil prices. The sale of purchased volumes generated an income of $48.5 million and $159.7 million, for the three and nine months ended September 30, 2023, respectively.

Royalties

($M)	Three months ended September 30		Nine months ended September 30	
	2023	2022	2023	2022
Royalties Colombia	12,033	24,183	30,690	75,320
Royalties Ecuador	183	188	576	313
Royalties	**12,216**	**24,371**	**31,266**	**75,633**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three and nine months ended September 30, 2023, royalties decreased by $12.2 million and $44.4 million, respectively, compared to the same periods of 2022, due to the change in the royalties payment method from in-cash to in-kind as per the ANH's request and lower WTI oil benchmark price. Refer to the "Production Reconciled to Sales Volumes" section on page 7 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Depletion, depreciation and amortization	61,756	57,927	209,858	146,221

For the three and nine months ended September 30, 2023, depletion, depreciation, and amortization expense ("**DD&A**") increased by 7% and 44%, respectively, compared to the same period of 2022, mainly due to a higher depletable base as a result of an impairment reversal in fourth quarter 2022 and the acquisition of an additional 35% W.I. in the El Dificil block, on April 27, 2022.

Impairment Expense, Exploration Expenses and Others

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Impairment expense:				
Exploration and evaluation assets	—	—	19,503	2,264
Other	2,342	—	4,316	3,033
Total impairment expense	2,342	—	23,819	5,297
Exploration expenses of:				
Geological and geophysical costs, and other	435	498	1,214	1,450
Minimum work commitment paid	—	—	—	919
Total exploration expenses	435	498	1,214	2,369
Recovery of asset retirement obligations	3,480	969	(24,001)	(5,058)
Impairment, exploration expenses and other	**6,257**	**1,467**	**1,032**	**2,608**

Exploration and Evaluation Assets

During the three and nine months ended September 30, 2023, the Company recorded an impairment charge on exploration and evaluation of assets in Colombia of $Nil and $19.5 million, respectively (2022: $Nil and $2.3 million, respectively), as a result of the Company's decision to proceed with steps to relinquish the VIM-22 block, which remains subject to approval by the ANH.

Other

During the three and nine months ended September 30, 2023, the Company recognized other impairment expenses of $2.3 million and $4.3 million, respectively, related to obsolete inventories and allowance of doubtful account receivables, compared with $Nil and $3.0 million, during the three and nine months ended September 30, 2022, respectively.

Recovery of asset retirement obligation

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

During the three and nine months ended September 30, 2023, the Company recognized a recovery of asset retirement obligations of $3.5 million and $24.0 million, respectively (2022: $1.0 million and $5.1 million, respectively), mainly as a result of the sale of Frontera Energy Offshore Perú, the 100% consolidated entity that owns the 100% W.I. in Block Z1, for a payment of $7.5 million to a third party. As a result of this transaction, the Company derecognized the asset retirement obligation related to Block Z1 and generate a $37.4 million asset retirement obligation recovery.

Other Operating Costs

($M)	Three months ended September 30		Nine months ended September 30	
	2023	2022	2023	2022
General and administrative	11,925	12,549	37,016	42,302
Special projects and other cost [1]	2,916	969	8,345	2,234
Share-based compensation	1,018	1,422	1,893	5,927
Restructuring, severance and other costs	1,407	453	4,804	1,839

[1] *Mainly includes costs related to Promotora Agricola de los Llanos S.A., the SAARA (previously Agrocascada) expansion in 2023 and Peru.*

General and Administrative ("G&A")

For the three and nine months ended September 30, 2023, G&A expenses decreased by 5% and 12%, respectively, compared with the same periods of 2022, mainly due to lower professional fees.

Special projects and other costs

For the three and nine months ended September 30, 2023, special projects and other costs increased by $1.9 million and $6.1 million, respectively, compared with the same periods of 2022, mainly due to the SAARA project.

Share-Based Compensation

For the three and nine months ended September 30, 2023, share-based compensation decreased by $0.4 million and $4.0 million, respectively, compared with the same periods of 2022. The decrease was mainly due to the strengthening U.S. dollar, a decrease in the trading price of the Common Shares and the cancellation of certain share-based compensation. 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 and nine months ended September 30, 2023, restructuring, severance and other costs increased by $1.0 million and $3.0 million, respectively, compared with the same periods of 2022, mainly due to an increase in restructuring costs.

Non-Operating Costs

($M)	Three months ended September 30		Nine months ended September 30	
	2023	2022	2023	2022
Finance income	1,941	1,699	7,714	3,182
Finance expenses	(16,411)	(13,896)	(47,320)	(38,752)
Foreign exchange income (loss)	4,305	(38,745)	9,551	(48,183)
Other (loss) income	(1,207)	5,662	4,382	(5,419)

Finance Income

For the three and nine months ended September 30, 2023, finance income increased by $0.2 million and $4.5 million, respectively, compared with the same periods of 2022, as a result of higher interest rates on the investment trust accounts for abandonment requirements.

Finance Expenses

For the three and nine months ended September 30, 2023, finance expenses increased by $2.5 million and $8.6 million, respectively compared with the same periods of 2022, mainly due to higher interest on the PIL Loan Facility (as defined below) compared to the prior 2025 Puerto Bahía Debt (as defined below), and the new Citibank Working Capital Loan (as defined below), in addition to higher accretion expenses of asset retirement obligations.

Foreign Exchange Income (Loss)

For the three months ended September 30, 2023, foreign exchange income was $4.3 million, as a result of the COP appreciation against the USD, mainly related to the translation of the debt consolidated from the PIL Loan Facility. For the nine months ended September 30, 2023, foreign exchange income was $9.6 million, as a result of the COP appreciation against the USD, mainly related to the translation of the debt consolidated from the PIL Loan Facility offset by the transfer from the cumulative translation adjustment of the Other Comprehensive Income ("**OCI**") to Consolidated Statement of Income of a return of capital of Oleoducto de los Llanos S.A. ("**ODL**") for $6.8 million. This compares with losses of $38.7 million and $48.2 million, respectively, in the same periods of 2022, mainly related to the recycling of a cumulative translation adjustment relating to the return of capital of ODL for $19.1 million during the third quarter of 2022 and the COP's depreciation against the USD on the translation of the debt consolidated from Puerto Bahia. Foreign exchange rates for the third quarter of 2023 and 2022, were COP 4,053.76:1 and COP 4,532.07:1, respectively.

Other (Loss) Income

For the three and nine months ended September 30, 2023, the Company recognized other loss of $1.2 million and other income of $4.4 million, respectively. During the third quarter of 2023, the loss was mainly due to recognition expenses related to blocks relinquished. For the nine months ended September 30, 2023, the income is mainly related to the reversal of the legal claim from the late delivery of production from Quifa block prior to 2014. During the same periods of 2022, the Company recognized other income of $5.7 million and other loss of $5.4 million, respectively. Other income in 2022, was mainly from the sale of surplus inventory, while during the nine months ended September 30, 2022, the loss was due to the recognition of contingencies during the first half of the year 2022.

(Loss) Gain on Risk Management Contracts

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Premiums paid on oil price risk management contracts	(1,930)	(4,393)	(7,705)	(10,551)
Realized gain on foreign exchange risk hedge [(1)(2)]	4,112	—	13,070	—
Realized gain (loss) on risk management contracts	2,182	(4,393)	5,365	(10,551)
Unrealized (loss) gain on risk management contracts	(4,002)	(1,637)	4,880	(2,290)
Total (loss) gain on risk management contracts	(1,820)	(6,030)	10,245	(12,841)

(1) For the three and nine months ended September 30, 2023, includes $Nil and $9.0 million as a result of the early termination of zero-cost collars foreign exchange risk management contracts and cash settlement of foreign exchange risk management contracts by $4.1 million and $4.1 million, respectively.

(2) For determination of operating netback, during the three and nine months ended September 30, 2023, the Company estimates an attribution of 71% and 70% of the total realized FX hedge to production cost ($2.9 million and $9.1 million; 2022: $Nil and $Nil), respectively, and estimates an attribution of 18% and 19% of the total realized FX hedge to transportation ($0.7 million and $2.5 million; 2022: $Nil and $Nil), respectively. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.

For the three and nine months ended September 30, 2023, the realized gain on risk management contracts was $2.2 million and $5.4 million, respectively, resulting from a gain on cash settlement of risk management contracts of foreign exchange currency of $4.1 million during the third quarter of 2023 and unwinding of risk management contracts of foreign exchange currency of $9.0 million during the second quarter of 2023, compared to losses of $4.4 million and $10.6 million in the same periods of 2022 respectively, primarily from the lower cost of the put premiums settled during the nine months ended September 30, 2022.

For the three and nine months ended September 30, 2023, risk management contracts had an unrealized loss of $4.0 million and an unrealized gain of $4.9 million, respectively, compared to a loss of $1.6 million and $2.3 million in the same periods of 2022, 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 aims to protect a minimum of 40% up to 60% of the estimated production with a tactical approach, using derivative commodity instruments to protect the revenue generation and cash position of the Company, while maximizing the upside.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put	October to November 2023	Brent	118,000	70.00	5	—
Put	October to January 2024	Brent	1,390,000	80.00	1,573	—
Total as at September 30, 2023					1,578	—

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. As at September 30, 2023, 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	October to December 2023	COP / USD	60,000,000	3,914 / 4,320	4,479	—
Zero-cost collars	January to June 2024	COP / USD	30,000,000	4,100 / 4,550	274	—
Total as at September 30, 2023					4,753	—

Subsequent to September 30, 2023, the Company entered into new derivatives in order to hedge the currency risk exposure for the first half of 2024. The new transactions are as follows:

Type of Instrument	Term	Benchmark	Notional Amount / Volume in USD	Put / Call; Par forward (COP$)
Zero Cost Collar	January to June 2024	COP / USD	90,000,000	4,133 / 4,834

In addition, in connection to the Bancolombia Loan disbursement (as defined below), on October 31, 2023, the Company entered into a financial forward for the original loan amount, as follows:

Type of Instrument	Maturity Date	Benchmark	Notional Amount / Volume in USD	Forward Rate
Forward sale non-delivery	October 29, 2024	USD / COP	17,099,200	4,386

Income Tax Expense

	Three months ended September 30		Nine months ended September 30	
($M)	2023	2022	2023	2022
Current income tax expense	(15,333)	(8,584)	(27,141)	(11,162)
Deferred income tax expense	(17,679)	(93,778)	(15,996)	(169,514)
Total income tax expense	**(33,012)**	**(102,362)**	**(43,137)**	**(180,676)**

For the three and nine months ended September 30, 2023, the Company recognized a current income tax expense of $15.3 million and $27.1 million, respectively, compared to current income tax expense of $8.6 million and $11.2 million for the same periods of 2022. The increase in current income tax expense in 2023, as compared to the respective periods in 2022, is mainly to the recognition of an accounting provision for interest and penalties on a claim related to 2020 income taxes, plus the changes introduced by the 2022 tax bill.

For the three and nine months ended September 30, 2023, deferred income tax expense was $17.7 million and $16.0 million, respectively, as compared to the deferred income tax expense of $93.8 million and $169.5 million for the same periods of 2022. The variation is mainly due to the changes in the use of tax losses between both periods.

Net Income (loss)

	Three months ended September 30		Nine months ended September 30	
($M)	2023	2022	2023	2022
Net income (loss) [(1)]	32,582	(26,893)	101,459	88,819
Per share – basic ($)	0.38	(0.30)	1.19	0.96
Per share – diluted ($)	0.37	(0.30)	1.16	0.94

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

The Company reported a net income attributable to equity holders of the Company of $32.6 million for the third quarter of 2023, which included operating income of $65.0 million, $13.7 million of share of income from associates, foreign exchange gain of

$4.3 million and finance income of $1.9 million, partially offset by finance expenses of $16.4 million, other expenses of $1.2 million and income tax expenses of $33.0 million. This compared to a net loss of $26.9 million for the third quarter of 2022, which included an expense in deferred income taxes of $93.8 million, foreign exchange loss of $38.7 million and finance expenses of $13.9 million, partially offset by operating income of $118.2 million.

For the nine months ended September 30, 2023, the Company reported a net income attributable to equity holders of the Company of $101.5 million, which included operating income of $117.8 million, $41.6 million of share of income from associates, gain on risk management contracts by $10.2 million and foreign exchange gain of $9.6 million, partially offset by finance expenses of $47.3 million and income tax expenses of $43.1 million. This compared to a net income of $88.8 million, which included operating income of $346.6 million, partially offset by income tax expenses of $180.7 million, foreign exchange losses of $48.2 million and finance expenses of $38.8 million.

Capital Expenditures and Acquisitions

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Development drilling	27,807	44,145	98,716	120,146
Development facilities	19,957	9,863	54,137	27,262
Colombia and Ecuador exploration	12,322	7,083	38,067	27,962
Other	5,872	2,803	12,682	22,028
Total Colombia, Ecuador and other capital expenditures	**65,958**	**63,894**	**203,602**	**197,398**
Guyana exploration and infrastructure	8,172	12,124	156,840	86,000
Total capital expenditures [1]	**74,130**	**76,018**	**360,442**	**283,398**

[1] Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.

Capital expenditures for the three and nine months ended September 30, 2023, were $74.1 million and $360.4 million, respectively, an increase of $1.9 million and $77.0 million, respectively, compared to the same periods of 2022, mainly due to the following:

Development drilling. During the three and nine months ended September 30, 2023, development drilling expenditures decreased by $16.3 million and $21.4 million, respectively, compared to same periods of 2022. During the third quarter of 2023, 14 development wells were drilled in the Quifa, Cajua and CPE-6 blocks and one injector well was drilled at the CPE-6 block, while a total of 16 development wells were drilled in the same period of 2022 in the Quifa and CPE-6 blocks. During the nine months ended September 30, 2023, 52 development wells, including two injector wells, were drilled in the Quifa, CPE-6, Cajua and Cubiro blocks, while a total of 50 development wells drilled in the Quifa, CPE-6 and Guatiquia blocks in the same period of 2022. During 2023, the cost per well was lower compared to 2022, due to the type of well and efficiencies in the costs of the 2023 drilling campaign.

Development facilities. During the three and nine months ended September 30, 2023, development facilities expenditures increased from $9.9 million to $20.0 million, and from $27.3 million to $54.1 million, respectively, compared to the same periods of 2022, mainly related to new flow lines, the expansion and improvement of the development facilities in CPE-6 block, which will double water-handling capacity by the end of 2023. Additionally, the Company invested in new flow lines in the Quifa block to connect with SAARA project.

Colombia and Ecuador Exploration. During the three and nine months ended September 30, 2023, expenditures related to exploration activities increased by $5.2 million and $10.1 million, respectively, compared to same periods of 2022. During the three months ended September 30, 2023, one exploration well Perico Centro-1 (formerly Jandiayacu-1) and one appraisal well Yin-2, were drilled in Ecuador, which were optimized in design and costs reducing the amount invested per well compared to 2022. For the year ended September 30, 2023, a total of six exploration wells were drilled in Ecuador (two wells), VIM-22 (three well) and La Creciente (one well). In addition, during the second quarter of 2023, 3D seismic data was acquired in the Llanos-99 block. During the same periods of 2022, three exploration wells were completed in Perico block in Ecuador during the first half of 2022, one exploration well was spudded in Espejo block in Ecuador in September 2022. Details relating to exploration activities in Colombia and Ecuador are as follows:

Colombia. During the third quarter of 2023, the Company received approval from ANH to terminate by mutual agreement the CR-1 and COR-24 block commitments, which reduced exploratory commitments by $11.1 million. The Company's exploration focus remains on the Lower Magdalena Valley and Llanos Basins in Colombia. During the third quarter of 2023, the Company advanced on the processing of 163 square kilometers of 3D seismic data in the Llanos-99 block. In addition, the final PSTM volume was completed in October. The Company is working on pre-seismic and pre-drilling activities related to social and environmental studies in the Llanos-119, LLA-99, CPE-6 and VIM-46 blocks.

Ecuador. The Perico Centro-1 well (formerly Jandiayacu-1) was spudded on August 22, 2023, finding oil in three intervals, reached total depth of 11,198 ft MD on September 11, 2023. Petrophysical interpretation identified net pay in Lower U sand

19.5 ft, Upper Hollin 7.5 ft and Main Hollin 7.5 ft. The well was completed, and an initial test showed an average production of 800 bbl/d, approximately, (28 API) with 1% BSW. Clean-up activities are underway. The Company believes that the Upper Hollin presents additional exploration or production opportunity.

At the Jandaya-1, Tui-1 and Yin-1 exploration wells, in the Perico block (Frontera 50% W.I. and operator), the Company is conducting long-term testing and is preparing the environmental impact assessments in order to obtain a production environmental license. Currently, the Company has completed the four wells required as part of its exploration commitment on the Perico block. The Yin-2 appraisal well was drilled in July, discovering 48 feet of net pay in the Lower U sand and 24 feet net pay in the Hollin main formation.

Other

Other Capital Expenditures for the three and nine months ended September 30, 2023, were $5.9 million and $12.7 million, respectively, mainly related to investments in the SAARA project, maintenance expenditures and container cargo related infrastructure at Puerto Bahia.

Guyana exploration and infrastructure. During the three and nine months ended September 30, 2023, Guyana exploration and infrastructure expenditures were $8.2 million and $156.8 million, respectively, compared to $12.1 million and $86.0 million during the same periods of 2022, mainly related to the following:

Exploration. The Company and its majority-owned subsidiary and joint venture partner, CGX, in the Petroleum Prospecting License for the Corentyne block offshore Guyana (the "**PPL**"), announced that the Joint Venture has discovered a total of 114 feet (35 meters) of net pay at the Wei-1 well and a total net pay of 342 feet (104 meters) discovered to date on the North Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana.

The Joint Venture believes that the rock quality discovered in the Maastrichtian horizon in the Wei-1 well is analogous to that reported in the Liza Discovery on Stabroek block (see "Analogous Information"). Results further demonstrate the potential for a standalone shallow oil resource development across the Corentyne block.

Based on this data acquisition program and additional information provided through the independent laboratory analysis process, the Joint Venture reported in the Maastrichtian, Wei-1 test results and analysis confirm 13 feet (4 meters) of net pay in high quality sandstone reservoir. Fluid samples retrieved from the Maastrichtian and log analysis confirm the presence of sweet medium crude oil with a gas-oil ratio (GOR) of approximate 400 standard cubic feet per barrel.

In the Campanian, petrophysical analysis confirms 61 feet (19 meters) of net pay almost completely contained in one contiguous sand body with good porosity and moveable oil. Oil sampled during MDT testing as well as samples analyzed downhole confirm the presence of light crude oil in the Campanian. In the Santonian, petrophysical analysis confirms 40 feet (12 meters) of net pay in blocky sands with indications of oil in core samples.

Current interpretation of the Campanian and Santonian horizons show lower permeability and natural flow than the high-quality Maastrichtian; however, the Joint Venture believes these horizons may offer additional upside potential in the future.

The Company's investment in the Wei-1 well during the three and nine months ended September 30, 2023 was $6.8 million and $154.9 million, respectively.

Infrastructure. CGX, Frontera's majority-owned subsidiary, is building a multifunctional port facility adjacent to Crab Island on the eastern bank of the Berbice River in Guyana, 4.8 kilometres from the Atlantic Ocean, called the Berbice Deep Water Port, which will serve as an offshore supply base and a multi-purpose terminal (the "**Guyana Port Project**"). The land for the Guyana Port Project is leased until 2060 and is renewable for an additional term of 50 years. During the three and nine months ended September 30, 2023, the Company invested on infrastructure $1.4 million and $1.9 million, respectively, related to the Guyana Port Project's trestle.

Selected Quarterly Information

Operational and financial results		2023 Q3	2023 Q2	2023 Q1	2022 Q4	2022 Q3	2022 Q2	2022 Q1	2021 Q4
Heavy crude oil production	(bbl/d)	24,097	24,051	22,270	22,144	20,945	21,455	21,214	20,912
Light and medium crude oil combined production	(bbl/d)	13,964	15,188	16,518	17,073	17,428	17,348	17,248	16,300
Total crude oil production	(bbl/d)	38,061	39,239	38,788	39,217	38,373	38,803	38,462	37,212
Conventional natural gas production	(mcf/d)	5,250	5,626	8,590	9,097	9,969	10,374	9,530	4,663
Natural gas liquids production	(boe/d)	1,820	1,823	1,291	993	911	963	966	575
Total production	(boe/d)	40,802	42,049	41,586	41,806	41,033	41,586	41,100	38,605
Sales volumes, net of purchases	(boe/d)	35,289	35,799	30,424	34,323	36,660	33,273	28,211	39,001
Brent price	($/bbl)	85.92	77.73	82.10	88.63	97.70	111.98	97.90	79.66
Oil and gas sales, net of purchases [(1) (3)]	($/boe)	78.48	67.91	69.07	82.60	90.40	102.80	90.01	74.68
Premiums paid on oil price risk management contracts [(2)]	($/boe)	(0.59)	(0.80)	(1.16)	(1.32)	(1.30)	(1.15)	(1.06)	(1.87)
Royalties [(2)]	($/boe)	(3.76)	(3.02)	(3.36)	(6.04)	(7.23)	(10.57)	(7.58)	(3.62)
Net sales realized price [(1) (3)]	($/boe)	74.13	64.09	64.55	75.24	81.87	91.08	81.37	69.19
Production costs, net of realized FX hedge impact [(2) (3)]	($/boe)	(13.86)	(12.39)	(12.07)	(11.56)	(11.20)	(12.51)	(13.34)	(12.71)
Transportation costs, net of realized FX hedge impact[(2) (3)]	($/boe)	(11.73)	(10.89)	(11.20)	(10.55)	(10.70)	(10.80)	(9.72)	(9.02)
Operating netback per boe [(1)]	($/boe)	48.54	40.81	41.28	53.13	59.97	67.77	58.31	47.46
Revenue	($M)	308,867	289,869	250,366	317,568	354,548	344,015	254,627	301,969
Net income (loss) [(5)]	($M)	32,582	80,207	(11,330)	197,796	(26,893)	13,484	102,228	629,376
Per share – basic ($)	($)	0.38	0.94	(0.13)	2.29	(0.30)	0.14	1.08	6.60
Per share – diluted ($)	($)	0.37	0.92	(0.13)	2.25	(0.30)	0.14	1.05	6.40
General and administrative	($M)	11,925	12,422	12,669	12,761	12,549	15,097	14,656	12,144
Operating EBITDA [(4)]	($M)	137,800	116,461	91,922	144,994	173,207	190,678	132,998	148,645
Capital expenditures [(4)]	($M)	74,130	154,860	131,452	134,165	76,018	93,835	113,545	135,458

(1) Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(2) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.
(3) 2022 prior period figures are different compared with those previously reported as a result of the exclusion of ProAgrollanos' revenues and, production and transportation costs.
(4) Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22 for further details.
(5) Refers to net income (loss) attributable to equity holders of the Company.

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. Production volumes have increased since the fourth quarter of 2021, mainly due to the drilling activities, the investment in water handling facilities in Colombia and the start of oil production in Ecuador. However, during the third quarter of 2022, there was a decrease in production mainly due to maintenance of water disposal facilities at Quifa block, which was completed during the fourth quarter of 2022. In addition, there was a decreased in production during the third quarter of 2023, due to the return of the Neiva block following the completion of the block's production contract. During the last year, transportation costs have increased, mainly due to the initiation of a pipeline take-or-pay commitment that commenced in 2022 as part of the Conciliation Agreement between the Company, Cenit Transporte y Logistica de Hicrocarburos S.A.S. and Oleoducto Bicentenario de Colombia S.A.S (for further information, refer to note 26 of the 2022 Annual Consolidated Financial Statements), the annual increase of transportation tariffs and exchange rate impacts. Production costs have also fluctuated due to exchange rate impacts and increases in tariffs and barrels produced affecting variable costs.

Trends in the Company's net income (loss), attributable to equity holders of the Company, are also impacted most significantly by the recognition and derecognition of deferred income taxes and expenses or reversal of impairment of oil and gas and exploration and evaluation assets, DD&A, foreign exchange gain or losses and gain or losses from risk management contracts that fluctuate mainly with changes in hedging strategies and crude oil benchmark forward prices. Please refer to the Company's previously filed annual and interim management's discussion and analysis available on SEDAR+ at www.sedarplus.ca for further information regarding changes in prior quarters.

Midstream Colombia

Frontera has investment in certain infrastructure and midstream assets, including storage, port and other facilities in Colombia and the Company's investment in pipelines ("**Midstream Colombia Segment**").

The Company's Midstream 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 Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	100% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [2]

[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.

Performance Highlights

					Nine months ended September 30	
		Q3 2023	Q2 2023	Q3 2022	2023	2022
Operational and IFRS Results						
Volumes pumped at oil pipeline facility	(bbl/d)	251,988	243,490	216,116	240,519	209,758
Volumes throughput at port liquids facility	(bbl/d)	53,586	73,714	60,337	63,401	60,974
Volumes RORO at port general cargo facility	(Units)	25,346	29,516	34,445	85,082	90,239
Volumes at port Break Bulk Volumes	(Tons/m3)	43,535	4,782	7,310	59,351	69,316
Segment income	($M)	17,251	18,218	15,221	52,393	39,395
Segment cash flow from operations activities	($M)	19,168	20,101	14,364	46,877	46,368
Non IFRS Results [1]						
Adjusted Midstream Revenues	($M)	43,774	43,186	26,621	125,191	75,228
Adjusted Midstream EBITDA	($M)	29,878	31,076	17,588	89,130	48,335
Adjusted Midstream Cash	($M)	54,687	42,692	33,217	54,687	33,217
Adjusted Midstream Debt	($M)	123,778	123,459	131,443	123,778	131,443
Capital Expenditures Midstream Colombia Segment	($M)	2,341	363	555	3,540	1,855

[1] 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 22.

Midstream Colombia Segment Results

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

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Revenue	13,083	12,103	37,309	34,674
Liquids port facility	7,838	7,727	24,491	22,420
FEC liquids port facility	2,093	1,777	5,660	5,165
Third party liquids port facility	5,745	5,950	18,831	17,255
General cargo	5,245	4,376	12,818	12,254
Costs	(6,419)	(5,400)	(17,269)	(15,691)
General administrative expenses	(1,400)	(1,246)	(4,197)	(3,999)
Depletion, depreciation and amortization	(1,441)	(1,345)	(3,992)	(4,384)
Restructuring, severance and other costs	(298)	(57)	(1,101)	(1,113)
Puerto Bahia income from operations	**3,525**	**4,055**	**10,750**	**9,487**
Share of Income from associates ODL	13,726	11,166	41,643	29,908
Segment income	**17,251**	**15,221**	**52,393**	**39,395**
Segment cash flow from operations activities	**19,168**	**14,364**	**46,877**	**46,368**

The Company's Midstream Colombia Segment income increased by $2.0 million and $13.0 million for the three and nine months ended September 30, 2023, respectively, compared with the same periods of 2022 mainly due to the increase in share of income from associates ODL which increased by $2.6 million and $11.7 million respectively, driven by stronger crude oil volumes from the Cano Sur block. In addition, for the three and nine months ended September 30, 2023, the Puerto Bahia revenues increased by $1.0 million and $2.6 million, respectively, compared with the same periods of 2022. The liquids terminal revenues increased during the three months ended September 30, 2023 by $0.1 million mainly due to higher tarrifs partially offset by lower volumes of throughput, for the nine months ended September 30, 2023, increased by $2.1 million, due to higher tarrifs and additional volumes of throughput at port liquids facility. In addition for the three and nine months ended September 30, 2023 the general cargo terminal revenues increased by $0.9 million and $0.6 million, respectively, as a result of additional revenues from the shore base operation.

Cash provided by operating activities of the Midstream Colombia Segment for three months ended September 30, 2023 was $19.2 million, compared to $14.4 million in the same period of 2022. The increase was mainly due to fluctuations in non cash working capital. For the nine months ended September 30, 2023, cash provided by operating activities of the Midstream Colombia Segment was $46.9 million compared to $46.4 in the same period of 2022. The increase was mainly due to higher dividends collected partially offset by fluctuations in working capital.

Non-IFRS Results of Midstream Segment

The following table shows the financial metrics of the Midstream Colombia Segment attributable to Frontera, including the proportional consolidation of the 35% equity investment in the ODL pipeline. Reported adjusted Midstream revenue, adjusted Midstream operating costs and adjusted Midstream general and administrative costs for the Midstream segment reflecting Frontera's 35% interest in the ODL pipeline accounted for using the equity method for consolidated financial statement purposes. Adjusted Midstream EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the Midstream Colombia Segment business.

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Adjusted Midstream Revenue[(1)]	43,774	26,621	125,191	75,228
Adjusted Midstream Operating Costs[(1)]	(10,881)	(7,107)	(27,929)	(20,770)
Adjusted Midstream General and Administrative[(1)]	(3,015)	(1,926)	(8,132)	(6,123)
Adjusted Midstream EBITDA[(1)]	**29,878**	**17,588**	**89,130**	**48,335**

[(1)] 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 22.

The Adjusted Midstream EBITDA for the three and nine months ended September 30, 2023 increased by $12.3 million and $40.8 million, respectively, compared with the same periods of 2022, as a result of the increase from 59.93% to 100.00% in PIL at the end of September 2022, higher pipeline volumes transported, and higher throughput volumes at the liquids port facility.

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. On September 15, 2022, the Company acquired the remaining 40.07% interest it did not already own of PIL, increasing its ownership interest to 100%.

For the three and nine months ended September 30, 2023, ODL generated $70.3 million and $209.4 million of EBITDA, respectively, and $39.2 million and $119.0 million of net income, respectively. The ODL results are consolidated through the equity method in the Company's Interim Financial Statements as "Share of income from associates".

The income statement and key balance sheet information from the 100% ODL is as follows:

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Revenue	87,689	69,214	251,093	193,337
FEC revenue (billed units)	7,960	5,795	22,749	16,336
Third party revenues	79,729	63,419	228,344	177,001
Costs	(12,749)	(8,138)	(30,457)	(24,212)
General administrative expenses	(4,615)	(3,244)	(11,243)	(10,126)
Depletion, depreciation and amortization	(8,083)	(8,003)	(20,714)	(23,544)
Other non-operating expense	(1,911)	(747)	(5,631)	(3,971)
Income Tax	(21,113)	(17,179)	(64,067)	(46,031)
ODL Net Income	**39,218**	**31,903**	**118,981**	**85,453**

($M)	September 30 2023	December 31 2022
ODL debt	42,361	37,368
ODL cash and cash equivalents	59,757	65,004

The following table shows the volumes pumped per injection point:

	Three months ended September 30		Nine months ended September 30	
(bbl/d)	2023	2022	2023	2022
At Rubiales Station	179,310	140,958	168,290	136,942
At Jagüey and Palmeras Station	72,678	75,158	72,229	72,816
Total	**251,988**	**216,116**	**240,519**	**209,758**

The following table shows the volumes received per block:

	Three months ended September 30		Nine months ended September 30	
(bbl/d)	2023	2022	2023	2022
Rubiales	110,558	100,600	108,071	98,577
Quifa	29,725	25,908	29,681	27,082
CPE-6	2,248	2,095	2,156	1,421
Other blocks	95,800	80,775	84,958	77,205
Total	**238,331**	**209,378**	**224,866**	**204,285**

For the three and nine months ended September 30, 2023, the Company recognized $13.7 million and $41.6 million, respectively, as its share of income from ODL, which was $2.6 million and $11.7 million higher than the same periods of 2022, primarily due to the increase in volumes transported and the impact of foreign exchange fluctuations. During the three and nine months ended September 30, 2023, the Company recognized gross dividends of $Nil and $37.0 million, respectively, (2022: $Nil and $40.5 million, respectively) and recognized a return of capital of $Nil and $5.2 million, respectively (2022: $15.8 million and $19.7 million, respectively).

On October 31, 2023, ODL's shareholders approved a return of capital to the shareholders of approximately $14.8 million (equivalent to 30% of the outstanding capital contributions) payable on November 2, 2023. As a result, PIL received a $5.0 million cash payment from ODL.

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia, which consists of a hydrocarbons terminal and a general cargo terminal adjacent to the Bocachica access channel 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 liquid terminal with capacity of 2,672,000 barrels, and RORO services in the general cargo terminal.

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

	Three months ended September 30		Nine months ended September 30	
(bbl/d)	2023	2022	2023	2022
FEC volumes	13,789	16,052	13,163	13,197
Third party volumes	39,797	44,285	50,238	47,777
Total	**53,586**	**60,337**	**63,401**	**60,974**

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

	Three months ended September 30		Nine months ended September 30	
(units - tons/m3)	2023	2022	2023	2022
RORO (units) (1)	25,346	34,445	85,082	90,239
Break Bulk Volumes (Tons/m3) (2)	43,535	7,310	59,351	69,316

(1) Carry wheeled cargo, mainly corresponds to cars imported to Colombia.
(2) Other types of cargo different from wheeled cargo.

For the three and nine months ended September 30, 2023, Puerto Bahia has generated $3.5 million and $10.8 million of segment income from operations, respectively, and $5.3 million and $15.8 million of EBITDA, respectively.

During the third quarter of 2023, Puerto Bahia and Reficar entered into a connection agreement to connect Puerto Bahia's port facility and the Cartagena refinery via a 6.8-kilometre, 18-inch bi-directional hydrocarbon flow line. Once in service, the connection shall enable the continuous transport of crude oil and other hydrocarbons between Puerto Bahía's port facility and the Cartagena Refinery. The connection will be built, operated and maintained by Puerto Bahia and will have a capacity of up to 84,000 barrels per day. The connection will be capable of handling imported and domestically produced crude. Construction of the connection is expected to begin in the fourth quarter of 2023 and take approximately 12-18 months to complete at an anticipated total cost of approximately $30.0 million.

Preconstruction activities are underway, since the announcement in August 2023, the connection project has already achieved milestones in various key areas including technical, environmental and social matters, financing and procurement.

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 (loss) income as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA is a non-IFRS financial measure that represents the operating results of the Company's primary business, excluding the following items: restructuring, severance and other costs, post-termination obligation, 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.

Since the three and six months ended June 30, 2022, the Company changed the composition of its Operating EBITDA calculation to exclude certain unusual or non-recurring items as post-termination obligations and payments of minimum work commitments, which could distort future projections as they are not considered part of the Company's normal course of operations.

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

	Three months ended September 30		Nine months ended September 30	
($M)	**2023**	**2022**	**2023**	**2022**
Net income (loss) [1]	32,582	(26,893)	101,459	88,819
Finance income	(1,941)	(1,699)	(7,714)	(3,182)
Finance expenses	16,411	13,896	47,320	38,752
Income tax expense	33,012	102,362	43,137	180,676
Depletion, depreciation and amortization	61,756	57,927	209,858	146,221
Expense of impairment, (recovery) of asset retirement obligation and others, net	5,822	969	(182)	1,158
Post-termination obligation	1,377	—	7,654	7,070
Share-based compensation non-cash portion	305	59	841	4,564
Restructuring, severance and other costs	1,407	453	4,804	1,839
Share of income from associates	(13,726)	(11,166)	(41,643)	(29,908)
Foreign exchange (income) loss	(4,305)	38,745	(9,551)	48,183
Other loss (income)	1,207	(5,662)	(4,382)	5,419
Unrealized loss (gain) on risk management contracts	4,002	1,637	(4,880)	2,290
Non-controlling interests	(109)	2,579	(538)	4,982
Operating EBITDA	**137,800**	**173,207**	**346,183**	**496,883**

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

Capital expenditures

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

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Statements of Cash Flows				
Additions to oil and gas properties, infrastructure port, and plant and equipment	61,745	59,261	170,891	176,070
Additions to exploration and evaluation assets	12,169	16,511	190,039	108,235
Total additions in Statements of Cash Flows	**73,914**	**75,772**	**360,930**	**284,305**
Non-cash adjustments [1]	216	246	(488)	(907)
Total Capital Expenditures	**74,130**	**76,018**	**360,442**	**283,398**
Capital Expenditures attributable to Midstream Colombia Segment	2,341	—	3,540	—
Capital Expenditures attributable to other segments different to Midstream	71,789	76,018	356,902	283,398
Total Capital Expenditure	**74,130**	**76,018**	**360,442**	**283,398**

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

Midstream Colombia Calculations

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

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

	Three months ended September 30		Nine months ended September 30	
($M) [1]	**2023**	**2022**	**2023**	**2022**
Revenue Midstream Colombia Segment	13,083	12,103	37,309	34,674
Revenue from ODL	87,689	69,214	251,093	193,337
Direct participation interest in the ODL	35.00 %	20.98 %	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	30,691	14,518	87,882	40,554
Adjusted Midstream Revenues	**43,774**	**26,621**	**125,191**	**75,228**
Operating cost Midstream Colombia Segment	(6,419)	(5,400)	(17,269)	(15,691)
Operating Cost from ODL	(12,749)	(8,138)	(30,457)	(24,212)
Direct participating interest in the ODL	35.00 %	20.98 %	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	(4,462)	(1,707)	(10,660)	(5,079)
Adjusted Midstream Operating Costs	**(10,881)**	**(7,107)**	**(27,929)**	**(20,770)**
General and administrative Midstream Colombia Segment	(1,400)	(1,246)	(4,197)	(3,999)
General and administrative from ODL	(4,615)	(3,244)	(11,243)	(10,126)
Direct participating interest in the ODL	35.00 %	20.98 %	35.00 %	20.98 %
Equity adjustment participation of ODL [1]	(1,615)	(680)	(3,935)	(2,124)
Adjusted Midstream General and Administrative	**(3,015)**	**(1,926)**	**(8,132)**	**(6,123)**

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

($M) [1]	**September 30 2023**	**December 31 2022**
Cash and cash equivalents - unrestricted	189,190	289,845
Cash and cash equivalents of Non-Midstream Colombia Segment's	(155,418)	(263,431)
Total Cash Midstream Colombia Segment	33,772	26,414
Cash and cash equivalent from ODL	59,757	65,004
Direct participating interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	20,915	22,751
Adjusted Midstream Cash	**54,687**	**49,165**
Long-term debt	522,938	508,457
Debt of Non-Midstream Colombia Segment's	(413,986)	(405,363)
Total Debt	108,952	103,094
Debt from ODL	42,361	37,368
Direct participating interest in the ODL	35.00 %	35.00 %
Equity adjustment participation of ODL [1]	14,826	13,079
Adjusted Midstream Debt	**123,778**	**116,173**

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

Adjusted Midstream EBITDA

The Adjusted Midstream EBITDA is a non-IFRS financial measure used to assist in measuring the operating results of the Midstream Colombia Segment business. Refer to the Calculation in "Non-IFRS Results of Midstream Segment section on page 20.

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 10.

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 midstream segment from the per barrel metrics and adds the effects attributable to transportation and operating costs of any realized gain or loss on foreign exchange risk management contracts. Refer to the reconciliation in the "Operating Netback" section on page 9.

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 September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Produced crude oil and gas sales ($M) [(1)]	260,828	309,898	685,842	858,914
Purchased crude oil and products sales ($M)	48,532	58,479	159,745	138,159
(-) Cost of purchases ($M) [(2)]	(54,555)	(63,478)	(180,444)	(152,393)
Oil and gas sales, net of purchases ($M)	**254,805**	**304,899**	**665,143**	**844,680**
Sales volumes, net of purchases - (boe)	3,246,588	3,372,753	9,242,415	8,939,112
Oil and gas sales, net of purchases ($/boe)	78.48	90.40	71.97	94.49

[(1)] Excludes sales from port services as they are not part of the oil and gas segment. For further information, refer to the "Midstream Colombia" section on page 19.
[(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 September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Produced crude oil sales ($M)	258,042	305,496	676,451	846,443
Purchased crude oil and products sales ($M)	48,532	58,479	159,745	138,159
(-) Cost of purchases ($M)	(54,555)	(63,478)	(180,444)	(152,393)
Conventional natural gas sales ($M)	2,786	4,402	9,391	12,471
Oil and gas sales, net of purchases ($M) [(1)]	**254,805**	**304,899**	**665,143**	**844,680**
Sales volumes, net of purchases - (bbl)	3,147,019	3,205,111	8,923,612	8,453,041
Conventional natural gas sales volumes - (mcf)	567,754	955,588	1,817,714	2,773,700
Realized oil price, net of purchases ($/bbl)	80.08	93.76	73.49	98.45
Realized conventional natural gas price ($/mcf)	4.91	4.61	5.17	4.50

[(1)] Non-IFRS financial measure.

Net sales realized price

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

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Oil and gas sales, net of purchases ($M) (1)	254,805	304,899	665,143	844,680
(-) Premiums paid on oil price risk management contracts ($M)	(1,930)	(4,393)	(7,705)	(10,551)
(-) Royalties ($M)	(12,216)	(24,371)	(31,266)	(75,633)
Net sales ($M)	**240,659**	**276,135**	**626,172**	**758,496**
Sales volumes, net of purchases - (boe)	3,246,588	3,372,753	9,242,415	8,939,112
Oil and gas sales, net of purchases ($/boe)	78.48	90.40	71.97	94.49
Premiums paid on oil price risk management contracts (2)	(0.59)	(1.30)	(0.83)	(1.18)
Royalties ($/boe) (2)	(3.76)	(7.23)	(3.38)	(8.46)
Net sales realized price ($/boe)	**74.13**	**81.87**	**67.76**	**84.85**

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

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

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

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Production costs ($M)	54,942	42,263	153,714	138,937
(-) Realized gain on FX hedge attributable to production costs ($M) (1)	(2,927)	—	(9,136)	—
Production costs, net of realized FX hedge impact ($M) (2)	52,015	42,263	144,578	138,937
Production (boe)	3,753,784	3,775,067	11,323,221	11,255,216
Production costs, net of realized FX hedge impact ($/boe)	13.86	11.20	12.77	12.34

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

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

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

	Three months ended September 30		Nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Transportation costs ($M)	40,166	34,746	116,666	101,894
(-) Realized gain on FX hedge attributable to transportation costs ($M) (1)	(744)	—	(2,511)	—
Transportation costs, net of realized FX hedge impact ($M) (2)	39,422	34,746	114,155	101,894
Net production (boe)	3,359,564	3,248,796	10,126,662	9,792,699
Transportation costs, net of realized FX hedge impact ($/boe)	11.73	10.70	11.27	10.40

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

Supplementary Financial Measures

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

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

Royalties per boe

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

NCIB weighted-average price per share

Weighted-average price per share under the 2022 NCIB (as defined below) is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under the 2022 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 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; and
- debt service requirements relating to existing and future debt.
- enhancing shareholder returns through share repurchases.

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

As of September 30, 2023, the Company had a total cash balance of $221.2 million (including $32.0 million in restricted cash), which is $91.8 million lower than December 31, 2022. For the nine months ended September 30, 2023, the Company generated $338.4 million of cash from operations, which were used to fund cash outflows of $413.0 million for capital expenditures and other investing activities. For the nine months ended September 30, 2023, financing activities generated net outflows of $28.1

million, respectively, as a result of $114.9 million from net proceeds from the PIL Loan Facility (as defined below) and $20.0 million from Citibank Working Capital Loan (as defined below), $106.2 million toward repayment of the 2025 Puerto Bahia Debt, $8.7 million of constitution debt services reserve account for the PIL Loan Facility, $22.4 million of interest from borrowings, loans and other financing charges, $17.1 million toward Citibank Working Capital Loan, PIL Loan Facility and PetroSud Debt principal payments, $4.2 million in Common Shares purchased under the 2022 NCIB, and $3.2 million in lease payments. As a consequence, the Company's net working capital(1) increased by $59.2 million, to a deficit of $50.4 million compared to a deficit of $109.6 million at year-end 2022.

As at June 30, 2023, the net working capital was negative due to lower cash balance as a result of investments in capital expenditures and because since March 1, 2023, Colombia tax rules increased the self-withholding tax rates related to crude oil extraction and exportation from 4.6% to 9.9%.

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

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As of September 30, 2023, 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, for 2023 the request is expected in fourth quarter, and can be satisfied through additional allocations of restricted cash, designation of letters of credit, or a combination of both. As of September 30, 2023, the Company's restricted cash position was $32.0 million, an increase of $8.8 million from December 31, 2022, primarily due to the constitution of debt service reserve account of the PIL Loan Facility.

The measures taken by the Company to manage its liquidity and capital resources are ongoing and the Company continues to 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 working capital deficit, operational and capital requirements and other financial commitments. The Company intends to remain flexible and disciplined with respect to capital allocation decisions as the current commodity price environment evolves and can make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 35.

Unsecured Notes

The Company's long-term borrowing consists of the outstanding unsecured notes due on June 21, 2028 (the "**2028 Unsecured Notes**") in the aggregate principal amount of $400.0 million which were issued on June 21, 2021. The 2028 Unsecured Notes bear interest at a rate of 7.875% per year, payable semi-annually in arrears on June 21 and December 21 of each year, beginning on December 21, 2021. The 2028 Unsecured Notes will mature in June 2028, unless earlier redeemed or repurchased.

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, 2022, the 2028 Unsecured Notes were guaranteed by the Company's subsidiaries, Frontera Energy Colombia Corp. ("**Frontera Colombia**") and Frontera Guyana. 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 Company's outstanding 2028 Unsecured Notes (the "**Indenture**"). Frontera Colombia remains the sole guarantor of the 2028 Unsecured Notes.

Under the terms of the 2028 Unsecured Notes, the Company (excluding the Unrestricted Subsidiaries) may, among other things, incur indebtedness provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.25:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.25:1.0. In the event that these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $100.0 million and 10% of consolidated net tangible assets(3). The 2028 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at September 30, 2023, the Company is in compliance with all such covenants.

[1] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 22.

Pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $409,853,000 as of September 30, 2023, and for the twelve months ended as of September 30, 2023, consolidated adjusted EBITDA of $485,841,000 and consolidated interest expense of $30,035,000.

(1) Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the indenture governing the 2028 Unsecured Notes (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 (loss) income (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense and abandonment costs; after excluding the impact of the Unrestricted Subsidiaries.

(2) Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most 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 cash and cash equivalents. Both measures are exclusive of non-recourse subsidiary debt and certain amounts attributable to the Unrestricted Subsidiaries.

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

($M)		**As at September 30 2023**
Short-term and Long-term debt [1]	$	413,986
Total lease liabilities [2]		2,198
Risk management asset		(6,331)
Consolidated Total Indebtedness		**409,853**
(-) Cash and Cash Equivalents [3]		(138,345)
(=) Net Debt	**$**	**271,508**

(1) Excludes $109.0 million of long-term debt attributable to the Unrestricted Subsidiaries.

(2) Excludes $0.4 million of lease liabilities attributable to the Unrestricted Subsidiaries.

(3) Includes cash and cash equivalents attributable to the guarantors as of September 30, 2023, Frontera Colombia and the borrower (the Company) according to the Indenture.

Pipeline Investment Loan Facility

On March 27, 2023, PIL entered into a new credit agreement through which the lender 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 Bahía**") held by the Company and assets related to Puerto Bahia's liquids terminal, and is guaranteed by Frontera Bahía Holding Ltd., and Frontera ODL Holding Corp., the parent company of PIL (the **"PIL Loan Facility**"). The PIL Loan Facility is a 5-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 6-month term plus margin of 7.25% per annum and a $20.0 million bullet maturity tranche that pays a fixed rate of 11.00% 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. As at September 30, 2023, the carrying value of PIL Loan Facility was $109.0 million (2022: $Nil).

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, register and other professional fees.

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. The PIL Loan Facility has no impact on the Company's financial covenant calculations under its 2028 Unsecured Notes.

Puerto Bahia Secured Syndicated Credit Agreement

In October 2013, Puerto Bahia entered into a credit agreement with a syndicate of lenders in October 2013 for a $370 million debt facility, maturing in June 2025, for the construction and development of a multipurpose port in the Cartagena Bay (the "**2025 Puerto Bahia Debt**"). 2025 Puerto Bahia Debt had an interest rate of 6-month LIBOR plus 5% payable semi-annually. The 2025 Puerto Bahia Debt was secured by substantially all the assets and shares of Puerto Bahia. The 2025 Puerto Bahia Debt was non-recourse to the Company. On March 31, 2023, the 2025 Puerto Bahia Debt outstanding amount of $103.1 million plus accrued interest of $3.1 million was fully repaid with the funds provided by the PIL Loan Facility.

As at September 2023, Puerto Bahía and Frontera have no obligation under the 2025 Puerto Bahia Debt.

PetroSud Loans

On December 30, 2021, the Company acquired 100% of the issued and outstanding shares of 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. 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 September 30, 2023, 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 secured by a trust agreement that receives 100% of PetroSud's sales and contemplates a debt service account for an amount equal to 100% of the next scheduled debt service, and a debt service reserve account for an amount of $2.2 million. As at September 30, 2023, the outstanding amount under the PetroSud Debt was $8.7 million. 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. As of September 30, 2023, PetroSud was in compliance with all such covenants.

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 (approximately $18.0 million), maturing on October 29, 2024 with an interest rate of IBR(1) + 4.00%, payable quarterly (the "**Bancolombia Loan**"). On October 30, 2023, Bancolombia disbursed the total of the amount. The main purposes of the Bancolombia Loan is to fund general corporate purposes. In connection to the Bancolombia 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, and a maturity date on October 29, 2024.

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

Citibank Working Capital Loan

On June 5, 2023, the Company entered into a working capital loan agreement with Citibank NY (the "**Citibank Working Capital Loan**"). The Citibank Working Capital Loan is denominated in USD, for an amount of $20.0 million, and a maturity date of December 7, 2023. The Citibank Working Capital Loan bears interest equivalent to SOFR +4.25%, payable monthly, and amortizes in five equal installments from August to December 2023. Proceeds from this loan were used for general corporate purposes. As of September 30, 2023, the outstanding balance under the Citibank Working Capital Loan was $12.0 million, which was fully repaid during October 2023.

Letters of Credit

The Company has various uncommitted bilateral letters of credit lines. As of September 30, 2023, the Company had issued letters of credit and guarantees for exploration and abandonment fund totaling $124.6 million (total credit lines of $146.0 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 plant project at CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, for an amount equivalent to $6.3 million as at September 30, 2023, and a maturity date that is 72 months following the date conditions precedent to the financing are satisfied. The Solar Plant Debt bears interest equivalent to IBR +5.75%, payable monthly. As of September 30, 2023, the Company has drawn $2.7 million of the Solar Plant Debt, which has been disbursed from Bancolombia to Enel Colombia S.A. ESP, the developer of the CPE-6 solar plant project. The Company pays a monthly availability fee of 0.35% to Bancolombia for the principal amount that remains undisbursed.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at September 30, 2023, undiscounted by calendar year, are presented below:

As at September 30, 2023 ($M)	2023	2024	2025	2026	2027	2028 and Beyond	Total
Long term debt principal and interest	51,713	64,741	56,510	59,492	87,693	400,000	720,149
Lease liabilities	506	2,011	217	19	—	—	2,753
Total financial obligations	**52,219**	**66,752**	**56,727**	**59,511**	**87,693**	**400,000**	**722,902**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	17,910	71,642	35,870	—	—	—	125,422
ODL agreements	4,394	5,893	—	—	—	—	10,287
Other transportation and processing commitments	3,316	11,462	11,403	11,403	3,804	—	41,388
Exploration commitments							
Minimum work commitments (1) (2)	18,742	30,551	65,975	—	—	5,066	120,334
Other commitments							
Operating purchases, leases and community obligations	72,249	27,643	12,882	13,099	10,510	11,855	148,238
Total Commitments	**116,611**	**147,191**	**126,130**	**24,502**	**14,314**	**16,921**	**445,669**

(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.

(2) On July 17, 2023, the Company received a communication from the ANH accepting the termination of the CR1 contract by mutual agreement and without adverse consequences for the parties. CR1 had minimum outstanding commitments for a total of $8.8 million (the Company's net share of such commitment is $5.3 million) at the time of termination. On July 31, 2023, the Company received a communication from the ANH accepting the execution of $7.6 million investment in LLA-7, resulting in a reduction of the commitment in this amount. On August 4, 2023, the Company received an additional communication from the ANH accepting the termination of the COR-24 contract by mutual agreement and without adverse consequences for the parties. COR-24 had minimum outstanding commitments of $5.8 million at the time of termination.

Guyana Commitments

As at September 30, 2023, the Company, through its 76.05% interest in CGX and directly through its working interest, has certain work commitments under the Petroleum Prospecting License ("**PPL**") for the Corentyne block, offshore Guyana (Frontera 68% W.I. and non-operator). In accordance with the PPL for the Corentyne block, a second exploration well was required to be spud by January 31, 2023, which was extended from the previous expiry date of November 26, 2022. On January 23, 2023, CGX and Frontera, the majority shareholder of CGX and joint venture (the "**Joint Venture**") partner of CGX, announced that the Joint Venture had spud the Wei-1 well on the Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana. In addition, the Government of Guyana has approved an appraisal plan for the northern section of the Corentyne block, which commenced with the Wei-1 well. Following completion of Wei-1 drilling operations and upon detailed analysis of the results, the Joint Venture may consider future wells per its appraisal program to evaluate possible development feasibility in the Kawa-1 discovery area and throughout the northern section of the Corentyne block. The Joint Venture has complied with its exploration commitments under the Corentyne PPL.

On June 13, 2023, CGX and Frontera announced that the Joint Venture successfully reached total depth of 20,450 feet on the Wei-1 well. On June 28, 2023, CGX and Frontera announced that the Joint Venture discovered oil at the Wei-1 well, 210 feet of hydrocarbon bearing sands in the Santonian horizon were encountered. The Joint Venture successfully finished drilling operations without any safety incidents.

Following the safe and successful completion of Wei-1 well drilling operations, Frontera and CGX have entered into an agreement (the "**JOA Amending Agreement**") to amend the Joint Operating Agreement originally signed between a subsidiary of Frontera and CGX on January 30, 2019 (as amended from time to time), to cover the unexpected additional costs of the Wei-1 well due to delays associated with the late release of the rig by a third-party, costs associated with a lost sampling tool, and the drilling of the bypass well. The transactions contemplated by the JOA Amending Agreement remain subject to regulatory approvals.

As part of the JOA Amending Agreement, CGX will transfer up to 4.7% of its participating interest in the Corentyne block to Frontera in exchange for Frontera funding CGX's additional expected outstanding share of the Joint Venture's costs associated with the Wei-1 well for up to $16.5 million. As a result of the JOA Amending Agreement, if the full 4.7% participating interest is transferred by CGX and not re-assigned, Frontera will have a 72.7% participating interest and CGX will have a 27.3% participating interest in the Corentyne block.

In addition, in connection with (i) a drilling contract agreement (the "**Drilling Contract**") between Maersk Drilling Holdings Singapore Pte. Ltd. (now NobleCorp.) and CGX Resources Inc. ("**CGX Resources**"), the operator of the Corentyne block, for the provision of a semi-submersible drilling unit owned by NobleCorp. and associated services to drill the Joint Venture's Wei-1 well, and (ii) a services agreement (the "**Services Agreement**") between Schlumberger Guyana Inc. ("**Schlumberger**") and CGX Resources for the provision of certain oilfield services and the supply of related goods and products for the Corentyne block, Frontera entered into a deed of guarantee with each of NobleCorp. and Schlumberger for certain obligations. Each of the parent company guarantees provided by Frontera to secure payment obligations under the Drilling Contract and the Services Agreement is limited to a maximum amount of $30 million, provided that (i) in the case of Schlumberger, such maximum amount is automatically reduced in an amount equivalent to any payment received by Schlumberger; and (ii) in the case of NobleCorp. such maximum amount shall be reduced to the extent that NobleCorp receives payments under the Drilling Contract; provided, however, that until there are outstanding payments to be made under the Drilling Contract with NobleCorp, such maximum guaranteed amount shall not be reduced below $8.0 million. As of September 30, 2023, (i) the outstanding balance under the Services Agreement and the corresponding parent company guarantee was of $0.1 million; and (ii) there are no outstanding payments under the Drilling Contract or the corresponding parent company guarantee. The Company anticipates that during the fourth quarter of 2023 the outstanding balance under the Services Agreement will be paid in full.

As at September 30, 2023, CGX had entered into purchase orders and contracts for the drilling of the Wei-1 well and the Guyana Port Project, pursuant to which the Company has amounts outstanding of $2.6 million, which is expected to be paid during 2023 and early 2024.

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 July 5, 2023, the term of the pledge agreement has been extended up to March 31, 2024, with Ocensa, and up to April 30, 2024, with Cenit.

Other Guarantees and Pledges

As part of the Company's acquisition of Repsol Colombia Oil & Gas Ltd.'s ("**RCOG**") 50% working interest in the CPE-6 block, the Company granted a pledge to RCOG over the production from the CPE-6 block to guarantee the payments, up to a maximum of $48.0 million. Under the farm-out agreement, two kinds of payments are set, each contingent on production from this block and each applicable until the maximum payment of $48.0 million is paid: (i) a variable monthly payment, and (ii) three potential production milestone payments of $5.0 million each when 5 million, 10 million and 20 million total barrels production, respectively, are achieved. As at September 30, 2023, the Company has paid and accrued a total $17.4 million of such amounts under the agreement.

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 26 - Commitments and Contingencies of the 2022 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 statute of limitations barred Ecopetrol's judicial action. In addition, the Council of State ordered Ecopetrol to pay Frontera Colombia 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 filed by Ecopetrol due to its lack of constitutional relevance. The Company expects it is likely that Ecopetrol will appeal this decision.

Puerto Bahia –Tank Construction Related Arbitration

In the course of building its port facility, Puerto Bahia retained the services of Isolux Ingeniería S.A., Tradeco Industrial S.A. de C.V., Tradeco Infraestructura S.A. de C.V ("**CITT**") for the construction of the Hydrocarbons' Terminal, including eight storage tanks and other facilities (the "**EPC Contract**"). CITT failed to comply with the terms of the EPC Contract, including the timely delivery of the work contracted which caused damages to Puerto Bahia, among other contract breaches. As a result, Puerto Bahia proceeded to draw upon a letter of credit in the amount of $17.0 million granted by CITT as a guarantee of the EPC Contract (the "**LOC**"). On June 11, 2015, CITT initiated arbitration proceedings under the regulations of the International Chamber of Commerce of Paris, claiming, among other things: (i) the return of the money from the LOC; (ii) recognition of costs incurred during the execution of the EPC Contract due to the stand-by; (iii) the right to extend the contract term as per the changes requested by Puerto Bahia; and (iv) unlawful termination of the EPC Contract. On August 21, 2015, Puerto Bahia filed a counterclaim against CITT for failure to comply with its contractual obligations under the EPC Contract that led it to breach the delivery dates and the agreed schedules, generating over costs, damages, and losses to Puerto Bahia.

On March 1, 2023, the arbitral tribunal issued the arbitral award which (i) denied CITT's claim for an award of $68.4 million for the return of the LOC amount (including interests); (ii) rejected CITT's claim for damages of $14.9 million; (iii) confirmed that Puerto Bahia was entitled to terminate the EPC Contract, enforce the LOC, and charge penalties to CITT; (iv) granted Puerto Bahia a remedy of $24.7 million (i.e., special penalties of $14.4 million plus the termination penalty clause of $10.3 million); and (v) ruled to offset the $17.0 million LOC and $5.6 million awarded by the Tribunal to CITT as compensation for, among others, accepted invoices and procurement services rendered through June 5, 2015, for a final balance of $2.0 million in favour of Puerto Bahia, payable by any CITT member at an annual interest rate of 4%.

In September, 2023, CITT filed a constitutional action (tutela) against the award rendered on March 1, 2023. However, on September 29, 2023, Colombian Supreme Court issued a first instance ruling dismissing the constitutional action indicating that CITT cannot use it as a replacement of the annulment action which was not timely exercised. On October 4, 2023, CITT filed and appeal against the tutela decision.

Ecopetrol - Rubiales Field Disagreement

The Company has been involved in negotiations with Ecopetrol with respect to disagreements on wind-down costs and expenses, as well as inventory, in connection with the expiration of the Rubiales and Piriri exploration and production contracts in June 2016. On November 22, 2018, the Company filed a lawsuit against Ecopetrol before the Administrative Tribunal of Cundinamarca claiming it is owed $25.3 million. On August 16, 2022, Frontera was served with the admission of the lawsuit against Frontera for over $45.0 million filed by Ecopetrol, and on September 23, 2022, Frontera filed its statement of defense.

On June 30, 2022, Ecopetrol filed a second lawsuit against Frontera claiming approximately $4.1 million and on November 24, 2022, Frontera filed a second lawsuit against Ecopetrol before the Administrative Tribunal of Cundinamarca claiming it is owed $9.0 million.

On December 28, 2022, Frontera and Ecopetrol filed a joint settlement request before the General Attorney Office (the Procuraduría General de la Nación), pursuant to which the parties intend to settle 21 disagreements, including 13 related to Rubiales field disagreements, amounting to approximately $40.0 million in total. As part of the settlement, the parties will set off mutual debts as follows: Frontera will acknowledge that it owes Ecopetrol approximately $9.0 million and Ecopetrol will acknowledge that it owes Frontera approximately $5.0 million. On March 27, 2023, the General Attorney Office issued a favorable opinion concerning the joint settlement agreement. However, due to a mistake in the filing of the joint settlement agreement by the General Attorney Office before the courts, the proceeding was sent to three different judges, one of whom received the filling by error of the General Attorney Office and dismissed the settlement agreement arguing a lack of competence regarding those disagreements, considering that the competence of approving the settlement should fall upon the judges that have full knowledge of the litigation proceeding in accordance with Colombian law. Frontera and Ecopetrol challenged that decision and a final ruling is pending.

Tax reviews

The Company operates in various jurisdictions and is subject to assessments by tax authorities in each of those jurisdictions, which can be complex and based on interpretations. The Company is currently in discussions with tax authorities for various assessments with respect to certain income tax deductions relating to exportation expenditures, transportation costs, VAT credits, municipal taxes, and other expenses. As at September 30, 2023, the Company has assessed a possible tax exposure of

$142.8 million, (2022: $85.4 million) relating to these assessments for taxes, interest, and penalties. During the three and nine months ended September 30, 2023, the Company has included a provision of $10.5 million and $11.3 million, respectively (2022: $7.5 million and $7.5 million, respectively) mainly related to interest and penalties on a claim associated with 2020 income taxes. As at September 30, 2023, the carrying value of the tax liability provisions was $12.3 million (2022: $1.0 million).

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at November 9, 2023:

	Number
Common shares	85,431,716
Deferred share units ("**DSUs**") (1)	912,493
Restricted share units ("**RSUs**") (2)	1,985,933

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

On March 17, 2022, the Company launched a normal course issuer bid for its Common Shares(the "**2022 NCIB**"), pursuant to which the Company was permitted to purchase for cancellation up to 4,787,976 of its Common Shares during the twelve-month period that commenced on March 17, 2022 and ended on March 16, 2023, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules) as at March 7, 2022.

Purchases subject to the 2022 NCIB were carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc., on behalf of Frontera in accordance with an automatic share purchase plan and applicable regulatory requirements. During the three and nine months ended September 30, 2023, the Company purchased a total of 461,200 Common Shares. At its expiry on March 16, 2023, the Company repurchased for cancellation a total of 4,270,100 Common Shares under its 2022 NCIB for approximately $40.9 million.

The following table provides a summary of total share repurchases under the Company's 2022 NCIB program:

	Nine months ended September 30
	2023
Number of Common Shares repurchased	461,200
Total amount of Common Shares repurchased ($M)	4,170
Weighted-average price per share ($) (1)	9.04

(1) Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 22.

6. RELATED-PARTY TRANSACTIONS

The following table provides the total balances outstanding, commitments and transactional amounts with related parties, as at September 30, 2023 and December 31, 2022, and for the three and nine months ended September 30, 2023, and 2022, respectively:

		September 30, 2023, and December 31, 2022		Three Months Ended September 30	Nine Months Ended September 30
($M)		Accounts Payable	Commitments	Purchases / Services	
ODL	2023	5,793	10,287	7,960	22,749
	2022	2,553	31,796	5,795	16,336

The related-party transactions correspond to the ship-or-pay contract for the transportation of crude oil in Colombia for a total commitment of $10.3 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, the environment, its assets, regulatory environment and reputation, 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.

For a comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the Company´s AIF and the 2022 Annual Consolidated Financial Statements, copies of which are available on SEDAR+ at www.sedarplus.ca.

In addition, the COVID-19 pandemic could have negative impacts on the Company's financial condition, results of operations, and cash flows. Despite successful vaccine rollouts in many jurisdictions, the risk of a resurgence or additional variant strains continues to exist and could result in continued fluctuations in the price of oil and conventional natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events could have a material adverse effect on the Company's business, financial condition and results of operations. Even as the COVID-19 pandemic subsides, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic's global economic impact, long-term implications and risk of resurgences. To the extent that the COVID-19 pandemic adversely affects the Company's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described herein and other risks set forth in the Company's AIF and the 2022 Annual Consolidated Financial Statements, copies of which are available on SEDAR+ at www.sedarplus.ca.

Further, in February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. The outcome of the conflict continues to be uncertain and is having wide-ranging consequences on the world economy. In addition, certain countries, including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which are having far reaching effects on the global economy. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia are creating a significant worldwide supply shortage of oil and natural gas and have led to sustained high worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas is having a significant adverse impact on the world economy, including record high inflation levels. In addition, many Russian companies that provide goods and services for oil exploration and production may have been or may eventually become in the near future, subject to sanctions, or impacted by logistical and financial difficulties, which in turn may result in temporary shortages of certain materials/equipment needed for the oil and natural gas exploration and production. To date, these events have not impacted the Company's ability to carry on business, there have been no significant delays or direct security issues affecting the Company's operations, offices or personnel, and the enacted sanctions have not affected the Company's business. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain and the Company continues to monitor the evolving situation.

On October 7, 2023, Hamas terrorists infiltrated Israel's southern border from the Gaza Strip and conducted a series of attacks on civilian and military targets. Hamas also launched extensive rocket attacks on Israeli population and industrial centers located along Israel's border with the Gaza Strip and in other areas within the State of Israel. Following the attack, Israel's security cabinet declared war against Hamas and a military campaign against these terrorist organizations and has launched a series of responding attacks in Palestine. The outcome of the conflict continues to be uncertain and has the potential to have wide-ranging consequences on the world economy. Global oil prices have spiked since the beginning of the Israel-Palestine conflict. While neither Israel nor the Gaza Strip are significant oil producers, there is a risk that the conflict could lead to wider regional instability in the Middle East, home to some of the word's biggest oil producers. To date, these events have not impacted the Company's ability to carry on business, and there have been no significant delays or direct security issues affecting the Company's operations, offices or personnel. The long-term impacts of the conflict remain uncertain and the Company continues to monitor the evolving situation.

Subsequent to the quarter, the board of directors of the Company approved the Restructuring Plan, designed to improve 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 our workforce by approximately 16%. We may encounter challenges in the execution of these restructuring efforts that could prevent us from recognizing the intended benefits of the Restructuring Plan or otherwise adversely affect our business, results of operations and financial condition. As a result of the Restructuring Plan, we have 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 our operating margins. Our Restructuring Plan may result in other unintended consequences. If we experience any of these adverse consequences, our Restructuring Plan may not achieve or sustain its intended benefits, or the benefits, even if achieved, may not be adequate to meet our long-term profitability and operational expectations, which could adversely affect our business, results of operations and financial condition.

See the "Liquidity and Capital Resources" section on page 27 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 list 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 2022 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 2022 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 2 of the Interim 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 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 significant judgments and estimates made by management in the preparation of its financial information is provided in Note 3c of the 2022 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 the third quarter of 2023, management of the Company continued to monitor the impacts of COVID-19 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 continue to monitor and mitigate the risks associated with any changes to its control environment in response to the COVID-19 pandemic.

Management of the Company has evaluated the effectiveness of the Company's ICFR as at September 30, 2023.

Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at September 30, 2023.

There have been no changes in the Company's ICFR during the quarter ended September 30, 2023, 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 interim 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 September 30, 2023.

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				
					Nine months ended September 30	
Producing blocks in Colombia		**Q3 2023**	**Q2 2023**	**Q3 2022**	**2023**	**2022**
Heavy crude oil	(bbl/d)	21,575	21,455	16,667	20,876	17,164
Light and medium crude oil combined	(bbl/d)	11,875	13,144	15,267	13,011	15,604
Conventional natural gas	(mcf/d)	5,250	5,626	9,966	6,475	9,958
Natural gas liquids	(boe/d)	1,686	1,687	911	1,539	947
Net production Colombia	**(boe/d)**	**36,057**	**37,273**	**34,593**	**36,562**	**35,462**
Producing blocks in Ecuador						
Light and medium crude oil combined	(bbl/d)	460	433	719	532	418
Net production Ecuador	**(bbl/d)**	**460**	**433**	**719**	**532**	**418**
Total net production	**(boe/d)**	**36,517**	**37,706**	**35,312**	**37,094**	**35,880**

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.

Certain disclosures in this MD&A constitute “anticipated results” for the purposes of NI 51-101 because the disclosure in question may, in the opinion of a reasonable person, indicate the potential value or quantities of resources in respect of Frontera’s or the Joint Venture’s resources or a portion of its resources. Without limitation, the anticipated results disclosed in this MD&A release include “net pay” (and variations thereof) attributable to the resources of Frontera or the Joint Venture. Such estimates have been prepared by Frontera or the Joint Venture, as applicable,and have not been prepared or reviewed by an independent qualified reserves evaluator or auditor. Such terms should not be interpreted to mean there is any level of certainty in regard to the hydrocarbons present, or that hydrocarbons may be produced profitably, in commercial quantities, or at all. Anticipated results are subject to certain risks and uncertainties, including those described herein and various geological, technical, operational, engineering, commercial, and technical risks. In addition, the geotechnical analysis and engineering to be conducted in respect of such resources is not complete. Such risks and uncertainties may cause the anticipated results disclosed herein to be inaccurate. Actual results may vary, perhaps materially.

Analogous Information

Certain information in this presentation may constitute “analogous information” as defined in NI 51-101. Such information includes reservoir information retrieved from government or other publicly available sources, regulatory agencies or other industry participants that are independent of Frontera and CGX. Frontera believes the information is relevant as it may help to define the reservoir characteristics of certain lands in which the Joint Venture or Frontera holds an interest. Frontera is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor and is unable to confirm that the analogous information was prepared in accordance with NI 51-101. Such information is not an estimate of the resources attributable to lands held by the Joint Venture or Frontera and there is no certainty that the resources data and commercial viability for the lands held by the Joint Venture or Frontera will be similar to the information presented herein. The reader is cautioned that the data relied upon by the Joint Venture and Frontera may be in error and/or may not be analogous to such lands held by the Joint Venture or Frontera.

Abbreviations

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

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