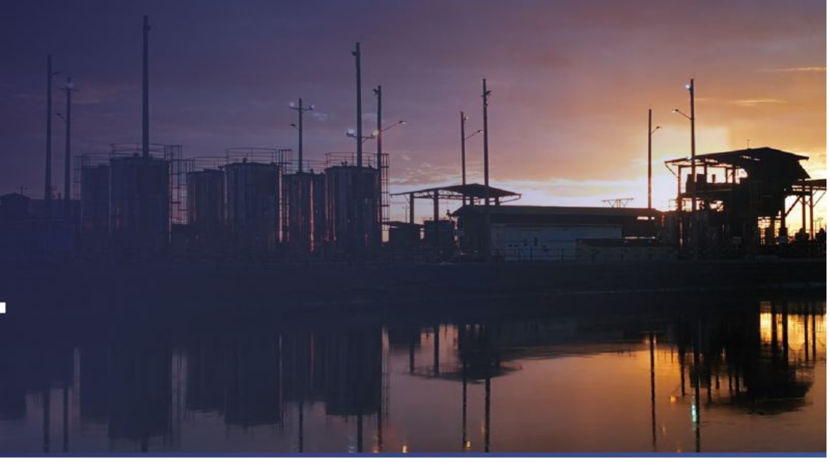
FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

March 1, 2023
For the year ended December 31, 2022



*Frontera Energy Corporation ("**Frontera**" 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 Consolidated Financial Statements and related notes for the years ended December 31, 2022 and 2021 ("**Annual Consolidated Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and its Annual Information Form (**"AIF"**), have been filed with Canadian securities regulatory authorities and are available on SEDAR at www.sedar.com 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 25.*

*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+**") and the impact of the Russia-Ukraine 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, 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 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; 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; 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. MESSAGE TO THE SHAREHOLDERS

2022 was marked by the ongoing Russia/Ukraine conflict, cautious post Covid-19 economic reopenings in China and increasing interest rates as governments around the world tried to stem the tide of rising global inflation. In Latin America, elections in Ecuador, Colombia and Brazil brought new governments, new policies and new impacts on industry. In Colombia, 2022 was a year of continued strong oil prices which supported robust financial returns offset by the introduction of political and regulatory change including the introduction of country-wide tax reforms which will have a significant impact on the oil and gas industry in 2023 and beyond. There was also tremendous oil price volatility in 2022 as Brent crude oil ranges traded as low as $76.10/bbl in December and as high as $127.98/bbl in March.

For Frontera, 2022 was a successful operating and financial year.

Building A Sustainable Future

Over the last three years, we have established a strong sustainability model at the core of our business through our “Building a Sustainable Future” environment, social and governance (ESG) strategy.

In 2022, Frontera achieved 102% of its ESG goals for the year. Notably, we offset 52% of our emissions through carbon credits, restored and reforested 1,747 hectares of key connectivity corridors in Casanare and Meta Departments, Colombia, compared with 765 hectares in 2021, and recycled 15% of our operating water and 17% of our solid waste. Frontera was awarded the Friendly Biz certification for our sexual discrimination-free and harassment-free environment, and received the Great Place-to-Work certification as one of the best companies to work for in Colombia. We invested approximately $4.31 million on education, inclusive economic development and quality of life initiatives, benefiting 73,101 people through 218 social projects in Ecuador, Peru and Colombia. Frontera was also recognized for the second consecutive year as one of the World's Most Ethical Companies by Ethisphere Institute.

Importantly, our employees achieved a best-ever Company total recordable injury rate of 0.82 in 2022.

Strategy

Our corporate strategy is to deliver value-focused production, cash flow, and reserves from our base Colombia operations, achieve continuous operational improvements across the business, create a standalone and growing midstream business in Sociedad Portuaria Puerto Bahía S.A. (“**Puerto Bahia**”) and Oleoducto de Los Llanos Orientales (“**ODL**”), advance our exciting development and exploration portfolio in Colombia, Ecuador and off-shore Guyana, return capital to shareholders and extend our track record of ESG delivery and performance across the business.

Guided by this strategy, we substantially delivered against our 2022 operating and financial objectives while safely and responsibly operating our business.

Operations

In 2022, Frontera executed $417.6 million in total capital spending in support of our Colombia and Ecuador upstream onshore business and our Guyana exploration program, optimizing both capital efficiency and free cash flow after development capex.

Colombia and Ecuador

From our Colombia and Ecuador business, we delivered average daily production for the year of 41,382 boe/d (consisting of 21,441 bbl/d of heavy crude oil, 17,274 bbl/d of light and medium crude oil, 9,741 mcf/d of conventional natural gas and 958 boe/d of natural gas liquids), a 9% increase compared to the Company’s 2021 production average and in-line with our 2022 increased and tightened production guidance. We capitalized on the sweet spots of our portfolio by investing in development facilities at VIM-1, drilling opportunities at the recently acquired Petroleos Sud Americanos S.A. (“**PetroSud**”) assets, development drilling at Quifa, exploration activities, and maintenance and production integrity activities across our portfolio. We also made discoveries on the Perico block at the Jandaya-1, Tui-1 and Yin-1 exploration wells and acquired a 35% W.I. in Colombia’s El Dificil block from PCR Investments S.A. for total cash consideration of $13 million.

Guyana

In Guyana, we discovered light oil and condensate in January at the Kawa-1 well on the offshore Corentyne block.

In December, Frontera and CGX completed an amendment to the joint operating agreement in respect of the Corentyne block originally signed between a subsidiary of CGX and a subsidiary of Frontera on January 30, 2019. Pursuant to the amendment, Frontera increased its participating interest in the Corentyne block to 68.00%, and agreed to fund the joint venture's costs associated with the Wei-1 well on the Corentyne block for up to $130 million and up to an additional $29 million of certain Kawa-1 exploration well costs, Wei-1 exploration well pre-drill, and other costs.

We also completed all pre-drill preparations in advance of spudding the Wei-1 well on January 20, 2023, on the Corentyne block, offshore Guyana. We are very excited about this potentially transformational opportunity in one of the most exciting exploration areas in the world and we look forward to safely and successfully drilling the Wei-1 well and potentially extending the Joint Venture's recent light oil and condensate discovery at the Kawa-1 well.

Midstream

In September 2022, the Company acquired the remaining 40.07% interest it did not already own in Pipeline Investment Ltd. ("**PIL**") for an aggregate cash consideration of approximately $47.4 million, including $21 million immediately following the closing of the transaction. The transaction represents an important milestone for the Company as it increases Frontera's interest in the ODL pipeline to 35%, strengthens Frontera's midstream cash flows, and creates a standalone and growing midstream business.

Reserves

Frontera continued to deliver strong reserves in 2022. In parallel with increased average daily production, the Company delivered 2P gross reserves of 175 mmboe with a net present value before taxes of $3.7 billion, an increase of 24% year-over-year. Importantly, the Company grew CPE-6 2P net reserves to 41 mmboe, while increasing annual average production from the block to approximately 5.300 boe/d of heavy crude oil, demonstrating the Company's success in increasing reserves from less mature fields and passing Quifa for the most net reserves per block in the Company. Frontera also increased gross gas and liquids reserves by 11% year-over-year to 21 mmboe, supporting the Company's efforts to further diversify its future production mix. Frontera has averaged 16.6 mmboe gross 2P reserves additions, achieved 108% reserves replacement ratio over the last three years, and a 11.6 year reserve life index.

Financials

I am pleased with Frontera's financial results in 2022. Compared to 2021, we increased cash provided by operating activities by 90% to $620.5 million, increased operating EBITDA by 70% to $641.9 million, increased our operating netback by 60% to $59.78/barrel, increased our net sales realized price by 40% to $82.59, reduced our restricted cash position by approximately $40 million and increased our uncollateralized credit lines to $118.4 million. We finished the year with a total cash position of approximately $313.0 million, including restricted cash of $23.2 million. Importantly, Fitch affirmed Frontera's IDR at 'B' with a stable outlook.

Shareholder Value Creation

Since 2018, Frontera has returned more than $300 million to shareholders through dividends and share buybacks while maintaining a strong credit profile.

In 2022, Frontera renewed its Normal Course Issuer Bid ("**NCIB**") and completed a Substantial Issuer Bid ("**SIB**"). Under the Company's current NCIB, which commenced on March 17, 2022, and will expire on March 16, 2023, Frontera is authorized to repurchase for cancellation up to 4,787,976 of the Company's common shares ("Common Shares"). As at March 1, 2023, the Company has repurchased approximately 4.3 million Common Shares for cancellation for approximately $40.9 million.

On June 24, 2022, the Company launched a SIB, pursuant to which the Company offered to purchase from shareholders for cancellation up to C$65.0 million of its outstanding Common Shares. On August 11, 2022, the Company announced that, in accordance with the terms and conditions of the SIB, the Company took up for cancellation 5,416,666 Common Shares at a price of C$12.00 per Common Share, for a total cost of $51.1 million (funded by cash, representing an aggregate purchase price of C$65.0 million plus transaction costs). The Common Shares taken up for cancellation under the SIB represented approximately 5.84% of the total number of the Company's issued and outstanding Common Shares as of August 8, 2022.

In total, we repurchased 9.6 million Common Shares, or 20% of the public float, for cancellation through our SIB and NCIB, returning more than $91.4 million to shareholders in 2022.

Frontera remains committed to returning capital to shareholders. As part of its 2023 plan, the Company will continue to consider future shareholder value enhancement initiatives.

Looking Ahead

In 2023, we will advance the Company's exciting development and near field exploration portfolio in Colombia and Ecuador; invest in infrastructure and facilities at Quifa and CPE-6 to increase production; leverage our advantaged transportation and logistics structure to maximize realized prices; mature our standalone and growing midstream business, including Puerto Bahia and ODL; execute our hedging program to protect our revenue generation and manage our exposure to price volatility; and seek to build on our Kawa-1 light oil and condensate discovery with the Wei-1 exploration and appraisal well, our second well offshore Guyana.

On behalf of Frontera's Board, Management team and all Frontera employees, thank you for your continued interest in and support of our Company. We look forward to safely and responsibly delivering our 2023 operating and financial objectives.

"Orlando Cabrales Segovia" (signed)
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q4 2022	Q3 2022	Q4 2021	Year ended December 31 2022	Year ended December 31 2021
Operational Results						
Heavy crude oil production [(1)]	(bbl/d)	22,144	20,945	20,912	21,441	19,326
Light and medium crude oil production [(1)]	(bbl/d)	17,073	17,428	16,300	17,274	17,218
Total crude oil production	(bbl/d)	39,217	38,373	37,212	38,715	36,544
Conventional natural gas production [(1)]	(mcf/d)	9,097	9,969	4,663	9,741	5,022
Natural gas liquids [(1)]	(boe/d)	993	911	575	958	393
Total production [(2)]	(boe/d) [(3)]	41,806	41,033	38,605	41,382	37,818
Total inventory balance	(bbl)	1,238,780	1,137,913	807,061	1,238,780	807,061
Oil and gas sales, net of purchases [(4)]	($/boe)	82.90	90.53	75.12	91.73	66.54
Realized loss on risk management contracts [(5)]	($/boe)	(1.32)	(1.30)	(1.87)	(1.22)	(4.01)
Royalties [(5)]	($/boe)	(6.04)	(7.23)	(3.62)	(7.83)	(2.66)
Dilution costs [(5)]	($/boe)	(0.07)	(0.07)	(0.10)	(0.09)	(0.72)
Net sales realized price [(4)]	($/boe)	75.47	81.93	69.53	82.59	59.15
Production costs [(5)]	($/boe)	(11.85)	(11.45)	(12.71)	(12.35)	(11.46)
Transportation costs [(5)]	($/boe)	(10.57)	(10.70)	(9.02)	(10.46)	(10.43)
Operating netback per boe [(4)]	($/boe)	53.05	59.78	47.80	59.78	37.26
Financial Results						
Oil & gas sales, net of purchases [(6)]	($M)	261,785	305,338	269,525	1,109,602	815,793
Realized loss on risk management contracts	($M)	(4,182)	(4,393)	(6,692)	(14,733)	(49,119)
Royalties	($M)	(19,076)	(24,371)	(12,974)	(94,709)	(32,572)
Dilution costs	($M)	(235)	(223)	(368)	(1,132)	(8,773)
Net sales [(6)]	($M)	238,292	276,351	249,491	999,028	725,329
Net income (loss) [(7)]	($M)	197,796	(26,893)	629,376	286,615	628,133
Per share – basic	($)	2.29	(0.30)	6.60	3.16	6.50
Per share – diluted	($)	2.25	(0.30)	6.40	3.08	6.29
General and administrative	($M)	12,761	12,549	12,144	55,063	52,134
Outstanding Common Shares	Number of Shares	85,592,075	86,575,175	94,695,694	85,592,075	94,695,694
Operating EBITDA [(6)]	($M)	144,994	173,207	148,645	641,877	378,179
Cash provided by operating activities	($M)	138,312	120,804	113,482	620,479	327,380
Capital expenditures [(6)]	($M)	134,165	76,018	135,458	417,563	314,257
Cash and cash equivalents – unrestricted	($M)	289,845	253,550	257,504	289,845	257,504
Restricted cash short and long-term [(8)]	($M)	23,202	55,552	63,321	23,202	63,321
Total cash [(8)]	($M)	313,047	309,102	320,825	313,047	320,825
Total debt and lease liabilities [(8)]	($M)	511,552	533,077	560,135	511,552	560,135
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(9)]	($M)	407,808	412,926	416,883	407,808	416,883
Net debt (excluding Unrestricted Subsidiaries) [(9)]	($M)	178,534	205,625	207,578	178,534	207,578

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 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 40.
3. Boe has been expressed using the 5.7 to 1 Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy. Refer to the "Further Disclosures - Boe Conversion" section on page 40.
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 25.
5. Supplementary financial measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
6. Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
7. Net income (loss) attributable to equity holders of the Company.
8. Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
9. "**Unrestricted Subsidiaries**" include CGX Energy Inc.(**"CGX"**), listed on the TSX Venture Exchange under the trading symbol "OYL", Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. (**"PIL"**), Frontera BIC Holding Ltd., and Frontera Bahía Holding Ltd. ("**Frontera Bahia**"), including its subsidiary Puerto Bahia. Refer to the "Liquidity and Capital Resources" section on page 29.

Performance Highlights

Full year 2022

- Production averaged 41,382 boe/d in 2022 (consisting of 21,441 bbl/d of heavy crude oil, 17,274 bbl/d of light and medium crude oil, 9,741 mcf/d of conventional natural gas and 958 boe/d of natural gas liquids), compared with 37,818 boe/d in 2021 (consisting of 19,326 bbl/d of heavy crude oil, 17,218 bbl/d of light and medium crude oil, 5,022 mcf/d of conventional natural gas and 393 boe/d of natural gas liquids).
- Cash provided by operating activities was $620.5 million in 2022, compared with $327.4 million in 2021, contributing to a total cash position as at December 31, 2022, of $313.0 million, compared with $320.8 million as at December 31, 2021. Total cash includes $23.2 million of restricted cash, compared with $63.3 million as at December 31, 2021.
- Net income(1) was $286.6 million ($3.08/share(2)) in 2022, compared with $628.1 million ($6.29/share(2)) in 2021.
- Capital expenditures were $417.6 million in 2022, compared with $314.3 million in 2021.
- Operating EBITDA was $641.9 million in 2022, compared with $378.2 million in 2021.
- Operating netback was $59.78/boe in 2022, compared with $37.26/boe in 2021.

Fourth Quarter 2022

- Production averaged 41,806 boe/d in the fourth quarter of 2022 (consisting of 22,144 bbl/d of heavy crude oil, 17,073 bbl/d of light and medium crude oil, 9,097 mcf/d of conventional natural gas and 993 boe/d of natural gas liquids), compared with 41,033 boe/d in the prior quarter (consisting of 20,945 bbl/d of heavy crude oil, 17,428 bbl/d of light and medium crude oil, 9,969 mcf/d of conventional natural gas and 911 boe/d of natural gas liquids), and an increase compared to 38,605 boe/d in the fourth quarter of 2021 (consisting of 20,912 bbl/d of heavy crude oil, 16,300 bbl/d of light and medium crude oil, 4,663 mcf/d of conventional natural gas and 575 boe/d of natural gas liquids).
- Cash provided by operating activities was $138.3 million in the fourth quarter of 2022, compared with $120.8 million in the prior quarter, and $113.5 million in the fourth quarter of 2021. The Company reported a total cash position of $313.0 million, including $23.2 million of restricted cash, as at December 31, 2022, compared with a total cash position of $320.8 million, including $63.3 million of restricted cash, as at December 31, 2021.
- The Company recorded a net income(1) of $197.8 million ($2.25/share(2)) in the fourth quarter of 2022, compared with net loss of $26.9 million ($0.30/share(2)) in the prior quarter and net income(1) of $629.4 million ($6.40/share(2)) in the fourth quarter of 2021.
- Capital expenditures were $134.2 million in the fourth quarter of 2022, compared with $76.0 million in the prior quarter and $135.5 million in the fourth quarter of 2021.
- Operating EBITDA was $145.0 million in the fourth quarter of 2022, compared with $173.2 million in the prior quarter and $148.6 million in the fourth quarter of 2021.
- Operating netback was $53.05/boe in the fourth quarter of 2022, compared with $59.78/boe in the prior quarter and $47.80/boe in the fourth quarter of 2021.

Oil and Gas Reserves

- Frontera added 11.6 MMboe of 2P gross reserves, for total Company 2P gross reserves of 174.8 MMboe and a reserve life index to 11.6 years at year end 2022.
- Frontera's 2022 year-end gross 2P reserves include additions of 4.8 MMboe by technical revisions mainly in CPE-6 and VIM-1 blocks, extensions of 4.0 MMboe mainly from CPE-6 block, 2.4 MMboe from the Company's acquisition of the remaining 35% W.I. in Colombia's El Dificil block, and 0.8 MMboe from exploration activities at Perico and Espejo blocks in Ecuador, offset by production of 15.1 MMboe. Proved gross reserves of 111.0 MMboe now represent 64% of the total 2P reserves compared with 66% of the total 2P reserves in 2021.

[1] Refers to Net Income Attributable to Equity Holders of the Company
[2] Per Share on a Diluted basis

3. GUIDANCE

The Company's 2022 financial and operational results were in-line with all revised 2022 annual guidance metrics (the "**2022 Guidance**"), with the exception of production costs which were over the high end, and EBITDA which was below the lower limit of EBITDA at $100/bbl Brent prices. The Company had previously updated its 2022 Guidance on August 9, 2022, at which time Frontera tightened its 2022 production guidance to 41,000-43,000 boe/d and increasing its operating EBITDA guidance to $675-$700 million at $100/bbl average Brent for the year 2022. Frontera also increased its total capital expenditures guidance for the year of $435-$495 million, primarily as a result of Frontera's increased working interest in the Corentyne block in Guyana, as previously announced on July 22, 2022, and reflective of the Company's spending commitment at the Wei-1 exploration well.

In 2022, production averaged 41,382 boe/d, in-line with the Company's increased and tightened 2022 Guidance of 41,000 to 43,000 boe/d.

Production costs of $12.35/boe were higher than the high end of 2022 Guidance of $11.00/boe to $12.00/boe, primarily due to an increase in tariffs and barrels produced affecting variable costs. Transportation costs of $10.46/boe were close to the midpoint of 2022 Guidance of $10.00/boe to $11.00/boe.

Operating EBITDA in 2022 totaled $641.9 million within the $90-$100/bbl 2022 Guidance range.

Capital expenditures of $417.6 million in 2022 was below the 2022 Guidance, mainly due to a delay in execution on the Wei-1 well was as a result of the spud postponement to January 2023.

		2022	
		Actual	Guidance
Average production	boe/d	41,382	41,000 - 43,000
Production costs(1)	$/boe	12.35	11.00 - 12.00
Transportation costs(2)	$/boe	10.46	10.00 - 11.00
Operating EBITDA at $90/bbl(3)	$MM	641.9	575 - 625
Operating EBITDA at $100/bbl(3)	$MM		675 - 700
Development Drilling	$MM	172.9	170 - 180
Development Facilities	$MM	48.2	50 - 60
Colombia and Ecuador Exploration	$MM	62.2	55 - 65
Other(4)	$MM	30.7	5
Total Colombia and Ecuador Upstream Capital Expenditures	$MM	314.0	280 - 310
Guyana Kawa-1 Well	$MM	51.0	51
Guyana Wei-1 Well(5)	$MM	49.4	100 - 130
Guyana Port Project	$MM	3.2	5
Capital Expenditures(6)	$MM	417.6	435 - 495

1. Supplementary financial measure (as defined in National Instrument 52-112 - Non-GAAP and Other Financial Measures Disclosure ("NI 52-112")). See "Non-IFRS and Other Financial Measures" section on page 25.
2. Supplementary financial measure (as defined in NI 52-112). See "Non-IFRS and Other Financial Measures" section on page 25. Calculated using net production after royalties.
3. Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). See "Non-IFRS and Other Financial Measures" section on page 25.
4. 2022 Guidance - Other does not include $12.0 million related to the acquisition of an additional 35% W.I. in the El Dificil block, or the payment $15.2 million related to the acquisition of a 50% interest in the CPE-6 block. For further information refer to the "Capital Expenditures and Acquisitions" section on page 19.
5. 2022 Guidance - Estimated Wei-1 well costs for 2022. Total Wei-1 well costs are estimated at approximately $130-$140 million (including pre-drill and other costs). The Wei-1 well was spud on January 23, 2023.
6. Non-IFRS financial measure (equivalent to a "non-GAAP financial measure", as defined in NI 52-112). See "Non-IFRS and Other Financial Measures" section on page 25. Capital Expenditures excludes decommissioning costs of $10.0 million.

2023 Guidance

The Company expects its total 2022 capital program to be approximately $385 - $455 million on a consolidated basis. This includes $110 - $130 million in development capital to maintain the Company's production volumes delivering 40,000 - 43,000 boe/d, $75 - $85 million on development facilities, primarily to increase oil and water handling capacity at the CPE-6 and Quifa blocks, and $50 - $60 million on exploration activities in Colombia and Ecuador. The Company anticipates spending between $120 - $140 million on Guyana exploration activities, primarily to drill the Wei-1 well. In addition, the Company anticipates investments of $5 - $10 million for Colombia infrastructure investments in Puerto Bahia (as defined below). The remaining capital budget of $25 - $30 million will be directed to other investments.

Production costs are expected to average $12.50/boe to $13.50/boe, higher than previous years, mainly due to the increased inflationary pressure, and higher energy and maintenance costs.

Transportation costs are expected to average between $10.50/boe to $11.50/boe, in-line with full year 2022 results. The Company anticipates generating operating EBITDA of approximately $375 - $425 million at $75/bbl Brent prices, $425 - $475 million at $80/bbl Brent prices, and $475 - $525 million at $85/bbl Brent prices.

In November 2022, the Colombian government approved tax reforms that will increase costs from 2023 onwards for Colombian oil and gas producers. The tax reform has two main impacts on the oil and gas industry. First, a 5 - 15% tax surcharge when current average oil prices are exceeded by 30% or more then average oil price over the last 10 years. Second, the tax reform makes royalties non-deductible. Treatment of high price participation (PAP) payments is not affected. Under the tax reform, oil and gas companies will not be permitted to deduct operating costs and capital expenditures associated with royalties paid whether in-kind or in-cash.

Summary of Frontera's 2023 Capital and Production Guidance

Guidance Metrics	Unit	2023 Full Year Guidance Frontera Consolidated
Average Daily Production(1)	boe/d	40,000 - 43,000
Production Costs(2)	$/boe	$12.50 - $13.50
Transportation Costs(3)	$/boe	$10.50 - $11.50
2023 Cash Income Taxes at $80/bbl	$MM	$40 - $60
Operating EBITDA(4) at $75/bbl(5)	$MM	$375 - $425
Operating EBITDA(4) at $80/bbl(5)	$MM	$425 - $475
Operating EBITDA(4) at $85/bbl(5)	$MM	$475 - $525
Development Drilling	$MM	$110 - $130
Development Facilities	$MM	$75 - $85
Colombia and Ecuador Exploration	$MM	$50 - $60
Colombia Infrastructure(6)	$MM	$5-10
Other(7)	$MM	$25-30
Total Colombia & Ecuador Capex	$MM	$265 - $315
Guyana Exploration	$MM	$120 - $140
Total Capital Expenditures(8)	$MM	$385 - $455

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, Peru and SAARA (previously Agrocascada) expansion in 2023.
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). The equivalent historical non-GAAP financial measure to 2023 operating EBITDA guidance is operating EBITDA for the year ended December 31, 2022, which was $641.9 million. Net income Attributable to Equity Holders of the Company is the most directly comparable financial measure to operating EBITDA. A reconciliation of Net Income Attributable to Equity Holders of the Company to operating EBITDA for the year ended December 31, 2022 and 2021 is set forth under "Non-IFRS Financial and Other Measures".
5. Current Guidance Operating EBITDA calculated at Brent $80/bbl and COP/USD exchange rate of 4600:1.
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. 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).

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2022, the Company received an independent certified reserves evaluation report ("**Reserves Report**") from DeGolyer and MacNaughton for all of its assets, with total gross 2P reserves of 174.8 MMboe compared with 178.2 MMboe certified reserves in 2021. All of the Company's booked reserves are located in Colombia and Ecuador.

Frontera's 2022 year-end gross 2P reserves include additions of 4.8 MMboe by technical revisions mainly in CPE-6 and VIM-1 blocks, extensions of 4.0 MMboe mainly from CPE-6 block, 2.4 MMboe from the Company's acquisition of the remaining 35% W.I. in Colombia's El Dificil block held by PCR Investments S.A. (a wholly-owned subsidiary of Petroquimica Comodoro Rivadavia S.A. ("PCR")), and 0.8 MMboe from exploration activities at Perico and Espejo blocks in Ecuador, offset by production of 15.1 MMboe. Proved gross reserves of 111.0 MMboe now represent 64% of the total 2P reserves compared with 66% of the total 2P reserves in 2021.

The Reserves Report was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook, NI 51-101 and CSA Staff Notice 51-324.

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

Reserves at December 31, 2022 (MMboe[1])								
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Quifa SW block	42.4	35.0	6.5	5.3	48.9	40.3	Heavy Crude Oil
	CPE-6 block	21.9	21.9	19.2	19.2	41.1	41.1	Heavy Crude Oil
	Other heavy oil blocks [2]	14.0	12.3	7.9	7.3	21.8	19.6	Heavy Crude Oil
	Light/medium oil blocks [3]	20.7	17.3	20.1	16.5	40.8	33.8	Light and Medium Crude Oil
	Natural gas blocks [4]	8.8	8.8	5.0	5.0	13.8	13.8	Conventional Natural Gas
	Natural gas blocks [4]	3.0	3.0	4.5	4.5	7.5	7.5	Natural Gas Liquids
	Sub total	**110.7**	**98.3**	**63.1**	**57.8**	**173.8**	**156.0**	**Oil, Conventional Natural Gas and Natural Gas Liquids**
Ecuador	Light/medium oil blocks[5]	0.3	0.2	0.6	0.5	0.9	0.7	Light and Medium Crude Oil
	Heavy oil blocks[5]	0.1	—	—	—	0.1	—	Heavy Crude Oil
	Sub total	**0.4**	**0.3**	**0.6**	**0.5**	**1.0**	**0.8**	**Oil**
	Total at Dec. 31, 2022	**111.0**	**98.6**	**63.8**	**58.3**	**174.8**	**156.8**	**Oil, Conventional Natural Gas and Natural Gas Liquids**
	Total at Dec. 31, 2021	118.3	109.3	60.0	57.7	178.2	167.0	
	Difference	(7.3)	(10.8)	3.8	0.6	(3.5)	(10.2)	
	2022 Production [6]	15.1	12.9	**Total reserves incorporated**		11.6	2.7	

1. See the "Further Disclosures - Boe Conversion" section on page 40.
2. Includes the Cajua and Jaspe fields in the Quifa block, and the Sabanero block.
3. Includes the Cubiro, Cravoviejo, Canaguaro, Guatiquia, Casimena, Corcel, Neiva, Cachicamo and other producing blocks.
4. Includes the VIM 1 and El Dificil blocks.
5. Includes the Perico and Espejo blocks, which are currently in early evaluation period to better quantify resources.
6. Gross production distribution: light & medium crude oil 6.2 MMboe, heavy crude oil 7.9 MMboe, conventional natural gas 0.6 MMboe, natural gas liquids 0.3 MMboe.
7. In the table above, "Gross" refers to W.I. before royalties, and "Net" refers to W.I. after royalties. Numbers in the table may not add due to rounding differences.

5. FINANCIAL AND OPERATIONAL RESULTS

Production

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

		Production				
Producing blocks in Colombia		**Q4 2022**	**Q3 2022**	**Q4 2021**	**FY 2022**	**FY 2021**
Heavy crude oil	(bbl/d)	22,144	20,945	20,912	21,441	19,326
Light and medium crude oil	(bbl/d)	15,827	16,224	16,300	16,436	17,218
Conventional natural gas	(mcf/d)	9,097	9,969	4,663	9,741	5,022
Natural gas liquids	(boe/d)	993	911	575	958	393
Total production Colombia	**(boe/d)**	**40,560**	**39,829**	**38,605**	**40,544**	**37,818**
Producing blocks in Ecuador						
Light and medium crude oil	(bbl/d)	1,246	1,204	—	838	—
Total production Ecuador	**(bbl/d)**	**1,246**	**1,204**	**—**	**838**	**—**
Total production	**(boe/d)**	**41,806**	**41,033**	**38,605**	**41,382**	**37,818**

Colombia

For the three months ended December 31, 2022, production increased by 731 boe/d compared to the prior quarter. Higher production was mainly due to the initiation of a new Battery 4 water disposal facility at the Quifa block which came on-line in October 2022. In addition, during the three months ended December 31, 2022, production in CPE6 increased by 144 bbl/d compared to the prior quarter, meeting a record production of 5,214 bbl/d of heavy crude oil in the fourth quarter of 2022. Increases were partially offset by lower production in light and medium crude oil and gas primarily due to natural decline.

Compared to the three months and year ended December 31, 2021, production increased by 5% and 7%, respectively, mainly due to (i) heavy oil increases in the Quifa and CPE-6 blocks from development drilling, and the reactivation of the Sabanero block, (ii) increases in the VIM-1 block as a result of the development of the facilities in the block, (iii) the acquisition of PetroSud on December 30, 2021, and the subsequent acquisition of an additional 35% W.I. in the El Dificil block on April 27, 2022, which resulted in the addition of 1,200 boe/d and 1,329 boe/d during the three months and year ended December 31, 2022, respectively (consisting of 5,196 mcf/d and 5,560 mcf/d of conventional natural gas, 230 bbl/d and 293 bbl/d of light and medium crude oil, and 58 bbl/d and 60 bbl/d of natural gas liquids, respectively). Increases were partially offset by lower production in light and medium crude oil, primarily due to natural decline.

Ecuador

Production in Ecuador for the three months and year ended December 31, 2022, was 1,246 bbl/d and 838 bbl/d, respectively, of light and medium crude oil. Production in Ecuador started during the first quarter of 2022 after discoveries at the Jandaya-1 and Tui-1 wells. Following the completion of the third exploration well, Yin-1, on June 16, 2022, at the Perico block, the three wells have been producing light and medium crude oil since the end of the second quarter of 2022. At the Espejo block (Frontera 50% W.I., and non-operator), the Pashuri-1 well started production in October 2022 producing an average of 68 bbl/d during fourth quarter 2022.

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.

					Year ended December 31	
		Q4 2022	**Q3 2022**	**Q4 2021**	**2022**	**2021**
Production	(boe/d)	**41,806**	**41,033**	**38,605**	**41,382**	**37,818**
Royalties in-kind Colombia	(boe/d)	(4,630)	(5,236)	(3,392)	(4,964)	(3,127)
Royalties in-kind Ecuador [1]	(boe/d)	(427)	(485)	—	(319)	—
Net production	(boe/d)	**36,749**	**35,312**	**35,213**	**36,099**	**34,691**
Oil inventory draw (build)	(boe/d)	(1,199)	3,207	6,697	(1,183)	845
Overlift (settlement)	(boe/d)	(12)	17	(1)	2	(155)
Volumes purchased	(boe/d)	9,587	6,841	3,861	6,143	2,868
Other inventory movements [2]	(boe/d)	(2,894)	(2,082)	(2,201)	(2,133)	(1,943)
Sales volumes	(boe/d)	**42,231**	**43,295**	**43,569**	**38,928**	**36,306**
Sale of volumes purchased	(boe/d)	(7,908)	(6,635)	(4,568)	(5,787)	(2,718)
Sales volumes, net of purchases	(boe/d)	**34,323**	**36,660**	**39,001**	**33,141**	**33,588**
Oil sales volumes	(bbl/d)	32,642	34,838	38,177	31,384	32,707
Conventional natural gas sales volumes	(mcf/d)	9,582	10,385	4,697	10,015	5,022
Total oil and conventional natural gas sales volumes, net of purchases	(boe/d)	**34,323**	**36,660**	**39,001**	**33,141**	**33,588**
Inventory balance						
Colombia	(bbl)	683,416	590,984	326,861	683,416	326,861
Peru	(bbl)	480,200	480,200	480,200	480,200	480,200
Ecuador	(bbl)	75,164	66,729	—	75,164	—
Inventory ending balance	**(bbl)**	**1,238,780**	**1,137,913**	**807,061**	**1,238,780**	**807,061**

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 December 31, 2022, decreased by 6% compared with the prior quarter mainly due to inventory buildup in Colombia and Ecuador. Since the second quarter of 2022, the Company has exported production from Ecuador, which amounted to in 755 bbl/d and 325 bbl/d for three months and year ended December 31, 2022, respectively.

For the three months ended December 31, 2022, total sales volumes, net of purchases, compared with the same quarter of 2021, decreased by 12% due to higher volumes sold in Colombia in the fourth quarter of 2021, as a consequence of drawdown of inventory balance build in previous quarters. For the year ended December 31, 2022, total sales volumes, net of purchases, was comparable with the same period 2021.

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. The PAP is paid in cash for all blocks except for those relating to the Quifa block, which are paid using in-kind volumes from production. 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).

					Year ended December 31	
		Q4 2022	**Q3 2022**	**Q4 2021**	**2022**	**2021**
PAP in cash	(bbl/d)	1,928	2,238	1,475	2,180	1,246
PAP in kind	(bbl/d)	2,459	3,150	1,683	2,752	820
PAP	**(bbl/d)**	**4,387**	**5,388**	**3,158**	**4,932**	**2,066**
% Production		**10.5 %**	**13.1 %**	**8.2 %**	**11.9 %**	**5.5 %**

For the three months and year ended December 31, 2022, PAP increased compared with the same periods of 2021, primarily due to a higher WTI oil benchmark price and the activation of the PAP clause on the CPE-6 block late in March 2022. For the three months ended December 31, 2022, PAP decreased compared with the prior quarter, mainly due to a lower WTI benchmark price.

Realized and Reference Prices

					Year ended December 31	
		Q4 2022	**Q3 2022**	**Q4 2021**	**2022**	**2021**
Reference price						
Brent	($/bbl)	88.63	97.70	79.66	99.04	70.95
Average realized prices						
Realized oil price, net of purchases	($/bbl)	85.82	93.89	76.23	95.42	67.72
Realized conventional natural gas price	($/mcf)	4.61	4.61	4.12	4.52	3.98
Net sales realized price						
Oil and gas sales, net of purchases (1)	($/boe)	82.90	90.53	75.12	91.73	66.54
Realized loss on risk management contracts(2) (3)	($/boe)	(1.32)	(1.30)	(1.87)	(1.22)	(4.01)
Royalties (2)	($/boe)	(6.04)	(7.23)	(3.62)	(7.83)	(2.66)
Dilution costs (2) (4)	($/boe)	(0.07)	(0.07)	(0.10)	(0.09)	(0.72)
Net sales realized price (1)	**($/boe)**	**75.47**	**81.93**	**69.53**	**82.59**	**59.15**

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
3. Includes put premiums paid for the position expired during the period.
4. Beginning in the second quarter of 2021, the Company moved from using a third-party dilution service to buying its own dilution at the corresponding fields (mainly at the Quifa block), using it for blending to meet pipeline specifications and other services, and then selling the blended oil at the sales point. The dollar difference between the cost of the purchases versus sales is approximately equivalent to how the Company accounted for the dilution costs in the past, or lower, considering the ability of the Company to secure better prices than a third-party dilution service. The decrease in dilution costs reflects decreased usage of the dilution service as the Company adopts this more cost-efficient approach.

The average Brent benchmark oil price during the three months and year ended December 31, 2022, increased by 11% and 40%, respectively, compared to the same periods of 2021. In comparison to the third quarter of 2022, the average Brent benchmark oil price decreased by 9%. The increase in crude oil prices in 2022 has resulted from the undersupply in the crude oil market due to low levels of inventories and reduction in OPEC+'s spare capacity, and the impacts of Russia-Ukraine conflict, which has affected the global crude oil supply. The decrease in crude oil prices compared with previous quarter is mainly due to three factors: (i) U.S. dollar strength as a result of worldwide recessionary sentiment caused by higher inflation leading to interest rate hikes, especially in the United States; (ii) Chinese demand reduction resulting from Covid-19 lockdowns; and (iii) higher Russian crude oil production despite the crude oil price cap imposed by the G7 countries.

For the three months and year ended December 31, 2022, the Company's net sales realized price was $75.47/boe and $82.59/boe, respectively, an increase of 9% and 40%, respectively, compared to the same periods of 2021. The increase was mainly a result of higher Brent benchmark oil prices, lower losses on risk management contracts, reduction in dilution costs, and improved differentials during 2022, partially offset by higher cash royalties. In comparison to the third quarter of 2022, the net sales realized price decreased by 8% or $6.46/boe, primarily driven by the decrease in Brent benchmark oil price and higher differential prices compared with the previous quarter, partially offset by lower royalties resulting from such Brent benchmark oil price decreases.

Operating Netback

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

	Q4 2022		Q3 2022		Q4 2021	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	238,292	75.47	276,351	81.93	249,491	69.53
Production costs (2)	(45,562)	(11.85)	(43,234)	(11.45)	(45,137)	(12.71)
Transportation costs (2)	(35,749)	(10.57)	(34,772)	(10.70)	(29,225)	(9.02)
Operating Netback (1) (3)	**156,981**	**53.05**	**198,345**	**59.78**	**175,129**	**47.80**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases (4)		34,323		36,660		39,001
Production (5)		41,806		41,033		38,605
Net production (6)		36,749		35,312		35,213

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
3. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
4. Sales volumes, net of purchases, exclude sales of third-party volumes.
5. Refer to the "Production" section on page 9.
6. Refer to the "Further Disclosures" section on page 40.

Operating netback for the fourth quarter of 2022 was $53.05/boe, compared to $47.80/boe in the same quarter of 2021. The increase was a result of a higher net sales realized price and lower production costs per boe as a result of higher volumes produced, partially offset by higher transportation costs mainly due to additional volumes transported in Ecuador during the fourth quarter of 2022 and the one-time prepaid services in Colombia recorded as lower transportation costs during the fourth quarter of 2021 after the implementation of the conciliation agreement between Frontera, Cenit Transporte y Logistica de Hidrocarburos S.A.S. ("**Cenit**") and Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") (the "**Conciliation Agreement**"). For further information, refer to Note 27 of the Company's Annual Consolidated Financial Statements and related notes for the years ended December 31, 2021 and 2020.

In comparison to the third quarter of 2022, the Company's operating netback for the fourth quarter of 2022 decreased from $59.78/boe to $53.05/boe, primarily due to lower net sales realized price as a result of lower average Brent benchmark oil prices.

The following table provides a summary of the Company's netbacks for year ended December 31, 2022:

	Year ended December 31			
	2022		2021	
	$M	($/boe)	$M	($/boe)
Net sales realized price [1]	999,028	82.59	725,329	59.15
Production costs [2]	(186,539)	(12.35)	(158,252)	(11.46)
Transportation costs [2]	(137,852)	(10.46)	(132,029)	(10.43)
Operating Netback [1] [3]	**674,637**	**59.78**	**435,048**	**37.26**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases [4]		33,141		33,588
Production [5]		41,382		37,818
Net production [6]		36,099		34,691

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
3. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
4. Sales volumes, net of purchases, exclude sales of third-party volumes.
5. Refer to the "Production" section on page 9.
6. Refer to the "Further Disclosures" section on page 40.

Operating netback for year ended December 31, 2022, increased to $59.78/boe from $37.26/boe in 2022. The increase was primarily due to a higher net sales realized price partially offset by higher production costs resulting from increased energy tariffs, maintenance, internal transportation costs and well services. The transportation cost was comparable with the same period 2021, despite the initiation of the pipeline take-or-pay commitment that commenced in 2022 as part of the Conciliation Agreement.

Sales

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
Oil and gas sales, net of purchases [1]	261,785	269,525	1,109,602	815,793
Realized loss on risk management contracts [2]	(4,182)	(6,692)	(14,733)	(49,119)
Royalties	(19,076)	(12,974)	(94,709)	(32,572)
Dilution cost	(235)	(368)	(1,132)	(8,773)
Net sales [1]	**238,292**	**249,491**	**999,028**	**725,329**
Net sales realized price ($/boe) [3]	75.47	69.53	82.59	59.15

1. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
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 25.

Oil and gas sales, net of purchases, for the three months ended December 31, 2022, decreased by $7.7 million compared to the same period of 2021, mainly due to fewer barrels sold, partially offset by higher Brent benchmark oil prices and better price differentials. During the year ended December 31, 2022, oil and gas sales, net of purchases, increased by $293.8 million compared to the year ended in 2021, mainly due to higher Brent benchmark oil prices and better differential prices. (Refer to the "Realized and Reference Prices" section on page 11 for further detail on changes in prices)

Net sales for the three months ended December 31, 2022, decreased by $11.2 million compared with fourth quarter 2021, and for the year ended December 31, 2022, increased by $273.7 million, compared with the 2021. The following table describes the various factors that impacted net sales:

	Three months ended December 31	Year ended December 31
($M)	**2022-2021**	**2022-2021**
Net sales for the period ended December 31, 2021	249,491	725,329
Increase due to 10% higher oil and gas price (YTD 38% higher)	27,940	308,775
Decrease due to lower own volumes sold	(35,680)	(14,966)
Decrease in realized loss on risk management contracts	2,510	34,386
Decrease in dilution costs	133	7,641
Increase in royalties	(6,102)	(62,137)
Net sales for the period ended December 31, 2022	**238,292**	**999,028**

Oil and Gas Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021
Cost of purchases [1]	64,746	37,176	216,243	82,725
Production costs	45,562	45,137	186,539	158,252
Transportation costs	35,749	29,225	137,852	132,029
Post-termination obligation	5,229	322	12,299	4,980
Dilution costs	235	368	1,132	8,773
Overlift (Settlement)	21	(3)	6	(2,641)
Inventory valuation	3,632	16,281	(6,877)	12,499
Total oil and gas operating costs	**155,174**	**128,506**	**547,194**	**396,617**

1. Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining activities. 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 25.

For the three months and year ended December 31, 2022, total oil and gas operating costs increased by 21% and 38%, respectively, compared to the same periods of 2021. The variance in total oil and gas operating costs was mainly due to the following:

- Cost of purchases for the three months and year ended December 31, 2022, increased by $27.6 million and $133.5 million, respectively, compared with the same periods of 2021, due to additional volumes of 3,340 bbl/d and 3,069 bbl/d, respectively, acquired from third parties to replace third-party dilution services, and higher Brent benchmark oil prices. The sale of the volumes purchased represents an estimated income for the three months and year ended December 31, 2022, of $62.5 million and $200.5 million, respectively.
- Production costs for the three months and year ended December 31, 2022, increased by 1% and 18%, respectively, compared with the same periods of 2021, primarily due to higher production costs resulting from increased energy tariffs, maintenance, internal transportation costs and well services. In addition, production costs for the year ended December 31, 2022, include $3.2 million of production costs from Ecuador.
- For the three months and year ended December 31, 2022, transportation costs increased by 4% and 22%, respectively, compared to the same periods of 2021, primarily due one-time prepaid services recorded as lower transportation costs during the fourth quarter of 2021 after the implementation of the Conciliation Agreement, and to higher volumes produced and transported in Colombia and Ecuador.
- Post-termination obligation for the three months and year ended December 31, 2022, was $5.2 million and $12.3 million, respectively, mainly related to non-recurring cleaning activities cost provision related to Block 192 in Peru.
- Dilution costs for the three months and year ended December 31, 2022, decreased by $0.1 million and $7.6 million, respectively, compared with the same periods of 2021, due to the replacement of third-party dilution service by volumes purchased and the optimization of the Company´s dilution strategy with natural gasoline, own and purchased light crude.
- Overlift for the three months and year ended December 31, 2022, was not significant, compared to the settlement of the overlift balance during the same periods of 2021.
- Inventory valuation for the three months and year ended December 31, 2022, decreased by $12.6 million and $19.4 million, respectively, compared with the same periods of 2021, mainly due to higher oil inventory costs as a result of an increase in royalties, and buildup of operating inventory.

Royalties

($M)	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021
Royalties Colombia	18,816	12,974	94,136	32,572
Royalties Ecuador	260	—	573	—
Royalties	**19,076**	**12,974**	**94,709**	**32,572**

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia and Ecuador. For the three months and year ended December 31, 2022, royalties increased by $6.1 million and $62.1 million, respectively, compared to same periods of 2021, primarily due to the increase in the WTI oil benchmark price and the activation of the PAP clause for the CPE-6 block in late March 2022. Refer to the "Production Reconciled to Sales Volumes" section on page 10 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

($M)	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021
Depletion, depreciation and amortization	49,198	20,121	195,419	126,692

For the three months and year ended December 31, 2022, depletion, depreciation and amortization expense ("**DD&A**") increased by 145% and 54%, respectively, compared to the same periods of 2021, mainly due to a higher depletable base as a result of the reversal of impairment in fourth quarter 2021 and the acquisition of PetroSud on December 30, 2021.

Impairment (Reversal) Expense, Exploration Expenses and others

($M)	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021
Impairment (reversal) expense:				
Properties, plant and equipment	(229,774)	(586,659)	(229,774)	(586,659)
Exploration and evaluation assets	18,644	26,009	20,908	26,009
Other	—	1,462	3,033	1,462
Total impairment (reversal) expense	(211,130)	(559,188)	(205,833)	(559,188)
Exploration expenses of:				
Geological and geophysical costs, and other	—	1,266	1,450	1,513
Minimum work commitment paid	—	—	919	—
Total exploration expenses	—	1,266	2,369	1,513
Recovery of asset retirement obligation	3,235	(3,332)	(1,823)	(6,335)
Impairment, exploration expenses and other	**(207,895)**	**(561,254)**	**(205,287)**	**(564,010)**

For the three months and year ended December 31, 2022, the Company recognized a net impairment reversal of $229.8 million. The Company's Reserves Report included higher forecasted oil prices, and as a consequence, a higher net present value than the carrying amount of the Company's oil and gas properties. As a result, the Company performed an impairment reversal test and concluded that the recoverable amount for the Central Cash Generating Units ("**CGUs**") exceeded its carrying amount resulting in a net reversal of previous impairment charges of $229.8 million.

The recoverable amount of each CGU was determined based on the Company's updated projections of future cash flows generated from proved and probable reserves. For further information refer to Note 9 of the 2022 Annual Consolidated Financial Statements.

During the three months and year ended December 31, 2022, the Company recorded an impairment of $18.6 million and $20.9 million, respectively, related to exploration and evaluation assets, as follows: i) In Colombia $15.0 million from the Magari-1D well at the La Creciente block that was unsuccessful in producing commercial quantities of hydrocarbons; and ii) in Ecuador $4.5 million partially impairment of the Pashuri-1 well at Espejo block due to initial lower than expected recoverable resources from the well. In addition, during the three months and year ended December 31, 2022, the Company recorded other impairment charges of $Nil and $3.0 million, respectively, mainly related to obsolete inventory of material in Peru.

During the three months ended December 31, 2022, the exploration expense decreased by $1.3 million compared with the same quarter of 2021, related to expenses incurred prior to obtaining the legal rights to explore an area, in the fourth quarter of 2021. For year ended December 31, 2022, the exploration expense increased by $0.9 million, compared with the same period of 2021, mainly due to execution of the payment of the remaining balance of a minimum work commitment not executed in the CPE-6 block.

During the three months ended December 31, 2022, the Company recognized a recovery related to asset retirement obligations of $3.2 million, compared to a recovery of $3.3 million in the same period of 2021. For year ended December 31, 2022, the Company recognized a recovery related to asset retirement obligations of $1.8 million, compared to a recovery of $6.3 million in the same period of 2021. 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.

For the three months and year ended December 31, 2021, the Company recognized an impairment reversal in property, plant and equipment of $586.7 million and $586.7 million, respectively, as the Company's certified 2021 year-end reserves report resulted in an increase in the total proved and probable reserves and a higher net present value than the carrying amount of its oil and gas properties. Additionally, for the three months and year ended December 31, 2021, the Company recognized impairment charges of $26.0 million and $26.0 million, respectively, related to exploration and evaluation assets, of which $20.1 million was recorded in Guyana, as a result of the Company prioritizing its work plan in the Corentyne block, and $5.9 million was recorded in in Colombia due to non-commercial exploratory test results, and plans to abandon further work on certain exploration projects in Colombia. Impairment charges of $1.5 million and $1.5 million, respectively, were recognized mainly related to slow moving or obsolete inventories.

Other Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
General and administrative	12,761	12,144	55,063	52,134
Share-based compensation	3,213	2,973	9,140	8,394
Restructuring, severance and other costs	2,624	1,746	4,463	4,616

General and Administrative ("G&A")

For the three months and year ended December 31, 2022, G&A expenses increased 5% and 6%, respectively, compared with the same periods of 2021, mainly due to higher professional fees, salaries and benefits.

Share-Based Compensation

For the three months ended December 31, 2022, share-based compensation was comparable with the same period of 2021, at $3.2 million. For the year ended December 31, 2022, share-based compensation increased by $0.7 million due to an increase in share price and a strengthening U.S. dollar, compared with the same periods in 2021. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units ("**RSUs**") and grants of deferred share units ("**DSUs**") under the Company's share based compensation plan, which are subject to variability from movements in the underlying Common Share price, and the consolidation of stock option expenses from the Company's majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months and year ended December 31, 2022, restructuring, severance and other costs decreased by $0.9 million and $0.2 million compared with the same periods of 2021, mainly due to a reduction in severance package and special projects in 2022.

Non-Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
Finance income	2,323	30	5,505	5,362
Finance expenses	(14,239)	(11,768)	(52,991)	(51,822)
Foreign exchange loss	(28,230)	(11,128)	(76,413)	(35,510)
Other (loss) income, net	(5,381)	14,788	(10,800)	1,435

Finance Income

For the three months ended December 31, 2022, finance income increased by $2.3 million, compared with the same period of 2021, as a result of higher interest rates on the investment trust accounts for abandonment requirements. Compared with the year ended December 31,2022, finance income increased by $0.1 million due to non-routine interest collected from a VAT reimbursement in the previous year.

Finance Expenses

For the three months and year ended December 31, 2022, finance expenses increased by $2.5 million due to higher interest on the 2025 Puerto Bahia Debt (as defined below), and bank guarantees. For the year ended December 31, 2021, finance expenses increased by $1.2 million mainly due to higher interest on the 2025 Puerto Bahia Debt partially offset by a reduction in the interest rate applicable to the 2028 Unsecured Notes (as defined below).

Foreign Exchange Loss

For the three months and year ended December 31, 2022, foreign exchange loss was $28.2 million and $76.4 million, respectively, as a result of the transfer from the cumulative translation adjustment of the OCI to Consolidated Statement of Income relating to the return of capital of ODL for $19.1 million during the third quarter of 2022. In addition, a loss was recorded as a result the of the depreciation of the COP against the USD on the translation of the 2025 Puerto Bahia Debt and a loss of the translation of the Company's net working capital balances. This compared with a loss of $11.1 million and $35.5 million in same periods of 2021. Foreign exchange rate COP:USD for the year ended December 31, 2022, were 4,810.20:1 compared with the same period of 2021, 3,981.16:1.

Other (Loss) Income, Net

For the three months and year ended December 31, 2022, the Company recognized other losses of $5.4 million and $10.8 million, respectively, primarily related to the recognition of contingencies. Compared to other income of $14.8 million and $1.4 million in the same periods of 2021, mainly due to a gain of $12.8 million from a bargain purchase resulting from the acquisition of PetroSud, partially offset for the year from the provision of the allegedly late delivery of production from the Quifa block prior to 2014 (for further information refer to the "Commitments and Contractual Obligations" section on page 32).

Loss on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
Premiums paid on risk management contracts settled	(4,182)	(3,646)	(14,733)	(11,462)
Cash settlement on risk management contracts	—	(3,046)	—	(37,657)
Realized loss on risk management contracts	(4,182)	(6,692)	(14,733)	(49,119)
Unrealized gain on risk management contracts [1]	6,600	4,530	4,310	7,213
Total loss (gain) on risk management contracts	2,418	(2,162)	(10,423)	(41,906)

1. Represents the mark-to-market change in the fair value of outstanding contracts and the reversal of prior unrealized amounts on contracts that settled in the period.

For the three months and year ended December 31, 2022, the realized loss on risk management contracts was $4.2 million and $14.7 million, respectively, resulting from cash paid for premiums related to put options settled during the period, compared to a loss of $6.7 million and $49.1 million, in the same periods of 2021, primarily from the higher cash settlement on three-way collars, puts and put spreads contracts paid during the three months and year ended December 31, 2021.

For the three months and year ended December 31, 2022, the unrealized gain on risk management contracts was $6.6 million and $4.3 million, respectively, compared to a gain of $4.5 million and $7.2 million in the same periods of 2021, primarily from the reclassification of amounts to realized loss from instruments settled and a decrease 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% 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. In 2022, the Company used only put options, which allowed the Company to capture the full upside price benefit while offering efficient downside hedging.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $/bbl**	**Assets**	**Liabilities**
Put	January 2023	Brent	460,000	80	341	—
Put	February to March 2023	Brent	840,000	70	875	—
Total as at December 31, 2022					1,216	—

Subsequent to December 31, 2022, the Company entered into new hedges that protect a portion of the Company's expected production for April and May 2023. The new transactions are as follows:

				Avg. Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $**
Put	April to May 2023	Brent	860,000	70
		Total (bbl)	**860,000**	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. The Company monitors its exposure to such foreign currency risks. As at December 31, 2022, the Company had entered into new positions of foreign currency derivatives contracts, detailed as follows:

Type of Instrument	Term	Benchmark	Notional Amount / Volume USD ($M)	Put/ Call; Par forward (COP$)	Carrying Amount Assets	Carrying Amount Liabilities
Zero-cost collars	January to June 2023	COP / USD	120,000,000	4,200 / 5,321	—	1,045
Total as at December 31, 2022					—	1,045

Subsequent to December 31, 2022, the Company entered into new derivatives in order to hedge the currency risk exposure for the third quarter of 2023. The new transactions are as follows:

Type of Instrument	Term	Benchmark	Notional Amount / Volume USD ($M)	Put/ Call; Par forward (COP$)
Zero-cost collars	July to September 2023	COP / USD	30,000,000	4,800 / 5,447
		Total USD	30,000,000	

Risk Management Contracts - Interest Rate Swap (2025 Puerto Bahia Debt)

Puerto Bahia has a financial derivative used to manage exposure to cash flow risks from the fluctuation of the interest rate expressed in LIBOR on the 2025 Puerto Bahia Debt. Refer to the "**Liquidity and Capital Resources**" section on page 29 for further information. As at December 31, 2022, Puerto Bahia has the following interest rate swap contract outstanding:

Type of Instrument	Term	Benchmark	Notional Amount $M	Avg. Strike Prices Floating rate	Carrying Amount ($M) Assets	Carrying Amount ($M) Liabilities
Swap	January 2023 to June 2025	LIBOR + 180	79,100	3.9%	1,092	0
Total as at December 31, 2022					**1,092**	**—**

Income Tax Expense (Recovery)

($M)	Three months ended December 31 2022	Three months ended December 31 2021	Year ended December 31 2022	Year ended December 31 2021
Current income tax expense	(76,021)	(2,178)	(87,183)	(26,568)
Deferred income tax recovery (expense)	7,422	38,296	(162,092)	25,529
Total income tax (expense) recovery	**(68,599)**	**36,118**	**(249,275)**	**(1,039)**

Current income tax expense for the fourth quarter of 2022 increased to $76.0 million, compared to $2.2 million for the same period of 2021, mainly due to higher taxable profits.

Deferred income tax recovery for the fourth quarter of 2022 was $7.4 million, compared with a recovery of $38.3 million, for the same quarter of 2021, with the change mainly due to recognition of the 2022 deferred tax asset.

For the year ended December 31, 2022, current income tax expense increased to $87.2 million, compared to $26.6 million for the same period of 2021, the difference was mainly due to higher taxable profits and a tax assessment of previous years.

Deferred income tax expense for the year ended December 31,2022, increased to $162.1 million compared with a recovery of $25.5 million for the same period of 2021. The change was mainly due to the utilization of the deferred tax asset and the Colombian peso devaluation.

Colombia 2022 Tax Bill

On December 13, 2022, the Colombian Government enacted a tax bill which established a permanent surtax for oil exploitation, surtax that is between 0% to 15% depending on the average oil price for the year. In addition, royalty payments for the exploitation of non-renewable resources will not be deductible from income tax purposes, and the value would be equivalent to the production costs of the volumes paid as royalties. The tax reform also repealed and ended accelerated amortization for exploration investments, the five years accelerated amortization for investments in exploratory activities carried out between 2017 and 2027 as well as the incentive credit (CERT) for oil investments. The changes will be applicable from 2023 and onwards.

Canada Tax Legislation

During 2021 and 2022, 136 countries and jurisdictions, including Canada (and Colombia), agreed to implement the Organization for Economic Co-operation and Development's (the "OECD") PillarTwo rules, effective in 2023. The proposed Pillar Two rules are designed to ensure that large multinational enterprises pay a minimum level of tax (currently agreed upon at 15%) on the income arising in each jurisdiction where they operate. The proposed rules remain subject to approval and ratification in multiple countries and jurisdictions. We are actively monitoring future developments on this proposed legislation and any potential impact on the Company.

Net Income

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
Net Income[(1)]	197,796	629,376	286,615	628,133
Per share – basic ($)	2.29	6.60	3.16	6.50
Per share – diluted ($)	2.25	6.40	3.08	6.29

1. Refers to Net income Attributable to Equity Holders of the Company.

The Company reported a net income, attributable to Equity Holders of the Company, of $197.8 million for the fourth quarter of 2022, which included operating income of $296.8 million (including a non-cash reversal of impairment of $229.8 million), partially offset by $68.6 million of income tax expense, foreign exchange loss of $28.2 million and finance expenses of $14.2 million. This compared to net income attributable to Equity Holders of the Company of $629.4 million in the fourth quarter of 2021, which included operating income of $697.1 million (including a non-cash reversal of impairment of $586.7 million) and $36.1 million income tax recovery, partially offset by $103.6 million related to currency translation adjustment ("**CTA**") as a result of the disposal of the Company's 43.03% interest in Bicentenario.

For year ended December 31, 2022, the Company reported a net income, attributable to Equity Holders of the Company, of $286.6 million, which included operating income of $643.4 million (including a non-cash reversal of impairment of $229.8 million), partially offset by income tax expenses of $249.3 million, foreign exchange losses of $76.4 million (primarily related to our midstream business) and finance expenses of $53.0 million. This compared to a net income, attributable to Equity Holders of the Company, of $628.1 million for year ended December 31, 2021, which included $854.2 million of operating income (including a non-cash reversal of impairment of $586.7 million), partially offset by $103.6 million related to the CTA as a result of the disposal of the Company's 43.03% interest in Bicentenario, $41.9 million loss on risk management contracts, $51.8 million finance costs expenses, and $29.1 million in debt extinguishment costs.

Capital Expenditures and Acquisitions

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
Development drilling	52,769	36,104	172,915	103,336
Development facilities	20,982	24,138	48,244	40,552
Colombia and Ecuador exploration	34,192	16,182	62,154	43,035
Other	8,690	462	30,718	1,743
Total Colombia, Ecuador and other capital expenditures	**116,633**	**76,886**	**314,031**	**188,666**
Guyana exploration	17,514	56,218	100,284	119,335
Guyana infrastructure	18	2,354	3,248	6,256
Total capital expenditures [(1)]	**134,165**	**135,458**	**417,563**	**314,257**

1. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.

Capital expenditures for the three months and year ended December 31, 2022, were $134.2 million and $417.6 million, respectively, a decrease of $1.3 million and an increase of $103.3 million, compared to the same periods of 2021, respectively. The variance in capital expenditures was mainly due to the following:

Development drilling. During the three months and year ended December 31, 2022, development drilling increased by $16.7 million and $69.6 million, respectively, compared to the same periods of 2021. During the three months ended December 31, 2022, a total of 17 development wells were drilled in the Quifa, Cajua, CPE-6 and Cubiro blocks and 1 injector well was drilled in the Quifa blocks, compared with 14 wells drilled in the Quifa, Guatiquia, CPE-6 and La Creciente blocks during same period of the year 2021. For the year ended December 31, 2022, 67 development wells were drilled in the Quifa, CPE-6, Cubiro, El Dificil and Guatiquia blocks, compared with 42 wells drilled in the Quifa, Guatiquia, CPE-6 and La Creciente blocks during the year 2021.

Development facilities. During the fourth quarter of 2022, development facilities decreased by $3.2 million compared to the same period of 2021, and for the year ended December 31, 2022, development facilities increased by $7.7 million compared with year ended December 31, 2021. During the three months and year ended December 31, 2022, the company invested mainly in road improvements and construction of an oil storage tank at the CPE-6 block; water pump improvements at the Quifa block; flow handling and injector line facilities at the Guatiquia block; overhauls of electrical and mechanical equipment; and the reactivation of facilities in the Sabanero block.

Colombia and Ecuador Exploration. During the three months and year ended December 31, 2022, exploration activities increased by $18.0 million and $19.1 million, respectively, compared to the same periods of 2021. During the fourth quarter of 2022, two exploration wells, the Pashuri-1 and Caracara-1 wells, were drilled in the Espejo block in Ecuador, and in Colombia four exploration wells were drilled, the La Belleza-2 well at the Vim-1 block, the Hamaca Norte-1 well at the CPE-6 block and the Magari-1 well was spud at the La Creciente block, while in the same period of 2021, the Company had completed the drilling of one well in Colombia and spud one exploration well in Ecuador.

Details relating to exploration activities during the year ended December 31, 2022, in Colombia and Ecuador are as follows:

Colombia. The Company continues to focus on the Lower Magdalena Valley and Llanos Basins in Colombia. At the Vim-1 block, the La Belleza-2 well was drilled as a horizontal well and encountered 2,000 feet of porous limestone in the Cienaga de Oro (“**CDO**”) formation then completed for natural flow production, in addition. At the La Creciente block Frontera spud the Magari-1 well and reached total depth in early January 2023. Gassy water was interpreted in the CDO formation and the well was plugged and abandoned. During the fourth quarter, at the VIM-1 and VIM-22 blocks the Company started pre-drilling activities in Chimi-1, Winner-1 and Tubara Sur-1, including civil works and environmental activities.

Ecuador. Following the first quarter 2022 completion of the Jandaya-1 and Tui-1 wells in the Perico block (Frontera 50% W.I. and operator) in Ecuador, the Company is under long-term test and will prepare the environmental impact assessments in order to obtain a production environmental license. On May 15, 2022, the Company spudded its third exploration well, Yin-1, on the Perico block, located approximately 0.53 kilometers to the southwest of the Jandaya-1 well in the northeastern portion of the block, reaching a total depth of 11,375 feet (3,467 meters). The Yin-1 well was completed on June 16, 2022. With this well, the Company has drilled three out of four wells required as part of its work commitment on the Perico block. A complete testing program is now being performed. Additional prospects on the Perico block have been identified and are being analyzed for future drilling.

At the Espejo block (Frontera 50% W.I. and non-operator), the operator, during the second quarter of 2022, completed the acquisition of 63 km2 of 3D seismic. During the fourth quarter of 2022, the Pashuri-1 well was drilled to a total depth of 10,907 feet (3,324 meters) in October 2022, and the Caracara-1 well was drilled, reaching a total depth of 10,090 feet (3,075 meters), in November 2022. Preliminary logging information indicated the presence of hydrocarbons in both wells. The Pashuri-1 well is currently producing approximately 400 bbl/d while initial production tests at the Caracara-1 well after six days of testing showed traces of heavy and viscous oil, and further analyses are being carried out to define next steps.

Other

For the three months and year ended December 31, 2022, the Company has capitalized other investments of $8.7 million and $30.7 million, respectively, mainly related to: (i) the acquisition of an additional 35% W.I. in the El Dificil block previously owned by PCR Investments S.A. (a wholly-owned subsidiary of Petroquímica Comodoro Rivadavia S.A. ("**PCR**")) for total aggregate cash consideration of approximately $12.0 million, which was completed on April 27, 2022, and added approximately 500 boe/d of total production (consisting of approximately 2,600 mcf/d of conventional natural gas and 45 bbl/d of natural gas liquids); (ii) $15.2 million related to a purchase agreement signed with Repsol Colombia Oil & Gas Ltd. (“**RCOG**”) to acquire its 50% of the CPE-6 block, as a result of reaching 5MMbbl of production during the first quarter of 2022 and the variable monthly payments made during year ended December 31, 2022 (for further information refer to the “Commitments and Contractual Obligations” section on page 32); (iii) investment in Puerto Bahia; and (iv) investment in the SAARA reverse osmosis water treatment facility.

Guyana

Guyana exploration. For the three months and year ended December 31, 2022, the Company invested $17.5 million and $100.3 million, respectively, in the Corentyne block, offshore Guyana, mainly related to final drilling activities at the Kawa-1 exploration well during the first quarter 2022, and pre-drilling activities for the Wei-1 exploration and appraisal well. Details relating to exploration activities in Corentyne block are as follows:

The Company and its majority-owned subsidiary and joint venture partner, CGX (the “**Joint Venture**”), completed drilling operations on the Kawa-1 well, located in the northern region of the Corentyne block, in the first quarter of 2022. The Kawa-1 well was drilled to a total depth of 21,578 feet (6,577 meters). Drilling results confirmed the presence of an active hydrocarbon system at the Kawa-1 location. Successful LWD and wireline logging runs confirmed net pay of approximately 228 feet (69 meters) within Maastrichtian, Campanian, Santonian and Coniacian horizons. Multiple datasets and analytic methods indicate the presence of gas condensate in the Maastrichtian and Campanian, and light oil in the Santonian and Coniacian. In January 2023, the Joint Venture spud the Wei-1 well, on the Corentyne block. 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. Any future drilling is contingent on positive results at the Wei-1 well and the Joint Venture has no further drilling obligations beyond the Wei-1 well. The Wei-1 well is located approximately 14 kilometers northwest of the Kawa-1 exploration well in the Corentyne block, approximately 200 kilometers offshore from Georgetown, Guyana and will be drilled in water depth of approximately 1,912 feet (583 meters) to an anticipated total depth of 20,500 (6,248 meters). The Wei-1 well will target Maastrichtian, Campanian and Santonian aged stacked sands within channel and fan complexes in the northern section of the Corentyne block. The well is expected to take approximately 4-5 months to reach total depth.

Guyana infrastructure. CGX, Frontera's majority-owned subsidiary, plans to build a multifunctional port facility adjacent to Crab Island on the Eastern Bank of the Berbice River in Guyana, 4.8 kilometers from the Atlantic Ocean, called the Berbice Deep Water Port, which is intended to 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 months and year ended December 31, 2022, CGX invested $Nil and $3.2 million, respectively.

Selected Quarterly Information

		2022				2021			
Operational and financial results		**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Heavy crude oil production	(bbl/d)	22,144	20,945	21,455	21,214	20,912	18,168	17,241	20,997
Light and medium crude oil production	(bbl/d)	17,073	17,428	17,348	17,248	16,300	17,160	17,142	18,294
Total crude oil production	(bbl/d)	39,217	38,373	38,803	38,462	37,212	35,328	34,383	39,291
Conventional natural gas production	(mcf/d)	9,097	9,969	10,374	9,530	4,663	5,033	5,164	5,227
Natural gas liquids	(boe/d)	993	911	963	966	575	211	393	391
Total production	(boe/d)	41,806	41,033	41,586	41,100	38,605	36,422	35,682	40,599
Sales volumes, net of purchases	(boe/d)	34,323	36,660	33,273	28,211	39,001	26,672	34,151	34,555
Brent price	($/bbl)	88.63	97.70	111.98	97.90	79.66	73.23	69.08	61.32
Oil and gas sales, net of purchases (1)	($/boe)	82.90	90.53	103.34	90.42	75.12	67.13	64.54	58.18
Realized loss on risk management contracts (2)	($/boe)	(1.32)	(1.30)	(1.15)	(1.06)	(1.87)	(2.68)	(8.00)	(3.53)
Royalties (2)	($/boe)	(6.04)	(7.23)	(10.57)	(7.58)	(3.62)	(4.83)	(0.53)	(1.96)
Dilution costs (2) (3)	($/boe)	(0.07)	(0.07)	(0.12)	(0.12)	(0.10)	(0.15)	(0.34)	(2.25)
Net sales realized price (1)	($/boe)	75.47	81.93	91.50	81.66	69.53	59.47	55.67	50.44
Production costs (2) (3)	($/boe)	(11.85)	(11.45)	(12.65)	(13.48)	(12.71)	(11.44)	(11.72)	(10.06)
Transportation costs (2) (3)	($/boe)	(10.57)	(10.70)	(10.84)	(9.74)	(9.02)	(10.24)	(11.15)	(11.30)
Operating netback per boe (1)	($/boe)	53.05	59.78	68.01	58.44	47.80	37.79	32.80	29.08
Revenue	($M)	317,568	354,548	344,015	254,627	301,969	182,673	224,685	184,734
Net income (loss)	($M)	197,796	(26,893)	13,484	102,228	629,376	38,531	(25,648)	(14,126)
Per share – basic ($)	($)	2.29	(0.30)	0.14	1.08	6.60	0.40	(0.26)	(0.14)
Per share – diluted ($)	($)	2.25	(0.30)	0.14	1.05	6.40	0.39	(0.26)	(0.14)
General and administrative	($M)	12,761	12,549	15,097	14,656	12,144	12,656	14,132	13,202
Operating EBITDA (4) (5)	($M)	144,994	173,207	190,678	132,998	148,645	77,304	83,072	69,158
Capital expenditures (5)	($M)	134,165	76,018	93,835	113,545	135,458	103,220	61,214	14,365

1. Non-IFRS ratio. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
2. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.
3. The second quarter of 2021 and prior period figures are different compared with those previously reported as a result of a reclassification from production costs to transportation costs and dilution costs by approximately $0.40/boe, $0.30/boe and $0.10/boe per quarter, respectively. The reclassification was related to certain logistic and refining processes fees of own crude oil previously recorded as production costs.
4. 2021 prior period figures are different compared with those previously reported as a result of the exclusion of post-termination costs.
5. Non-IFRS financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25 for further details.
6, Refers to Net Income 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. Since the first half of 2021, production volumes have increased due to the reactivation of drilling activities, removal of COVID-19 related restrictions that were imposed at the peak of the pandemic in Colombia and the starting of oil production in Ecuador. However, during the third quarter of 2022, there was a reduction in production mainly as a result of maintenance in water disposal facilities at the Quifa block, which was satisfactorily resolved during fourth quarter of 2022, and together with record production at the CPE-6 block, increased production again during the last quarter of 2022. During the year ended 2022, transportation costs were comparable with the same period 2021, despite the initiation of the pipeline take-or-pay commitment that commenced in 2022 as part of the

Conciliation Agreement. Dilution cost decreased, since the second quarter of 2021, as a result of the replacement of third-party dilution services by volumes purchased. Furthermore, production costs have increased due to an increase in tariffs and barrels produced affecting variable costs, such as maintenance, well services, energy, internal field transportation and community investment costs.

Trends in the Company's net income attributable to Equity Holders of the Company (loss) are also impacted most significantly by the recognition and derecognition of deferred income taxes and reversal of impairment of oil and gas assets, DD&A, foreign exchange gain or losses and total loss from risk management contracts that fluctuate mainly with changes in hedging strategies and crude oil benchmark forward prices. Refer to the Company's previously issued annual and interim management's discussion and analysis available on SEDAR at www.sedar.com for further information regarding changes in prior quarters.

Selected Annual Information

	As at and for the year ended December 31		
($M, except as noted)	**2022**	**2021**	**2020**
Revenue	1,270,758	894,061	648,508
Net income(1) (loss)	286,615	628,133	(497,406)
Per share – basic ($)	3.16	6.50	(5.13)
Per share – diluted ($)	3.08	6.29	(5.13)
Cash and cash equivalents	289,845	257,504	232,288
Total assets	2,738,455	2,611,080	2,063,912
Total non-current liabilities	530,194	566,144	567,241
Total liabilities	1,149,251	1,162,189	1,299,080

1. Refers to Net income Attributable to Equity Holders of the Company

Revenue increased to $1.3 billion in 2022 from $0.9 billion in 2021, and $0.6 billion in 2020. The revenue increase between 2022 and 2020 was mainly due to higher crude oil prices and higher production during 2022.

Net income, attributable to Equity Holders of the Company, for 2022 was $286.6 million, compared to a net income, attributable to Equity Holders, of the Company of $628.1 million in 2021, and a net loss of $497.4 million in 2020, as a result of recognition and derecognition of deferred income taxes and impairment or reversal of impairment of oil and gas assets, and higher operating EBITDA.

Total assets increased to $2.7 billion in 2022 from $2.6 billion in 2021, and increased from $2.1 billion in 2020, mainly as a result of the increase of investment activities and reversal of impairment in oil and gas properties in 2022 and 2021.

Cash and cash equivalents increased to $289.8 million in 2022 from $257.5 million in 2021, and $232.3 million in 2020 as a result of a higher cash flows from operations due to increase in oil prices.

Midstream Colombia

The Company has investments in certain infrastructure and midstream assets, including storage, port and other facilities relating to the distribution and exportation of crude oil products in Colombia and the Company's investments in pipelines ("**Midstream Colombia Segment**").

The Midstream Colombia Segment principally includes the following assets:

Project (1)	Description	Interest (2)	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	99.80% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/d	100% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method (3)

1. The Midstream Colombia Segment also includes the Company's interest in three other pipelines in Colombia: the Oleoducto Guaduas-La Dorada pipeline, Oleoducto del Alto Magdalena pipeline, and the Oleoducto de Colombia pipeline. Results of operations from these pipelines are not significant to the Company's consolidated financial results.
2. Interests include both direct and indirect interests.
3. 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.

Midstream Colombia Segment Results

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

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
Revenue	12,209	19,186	46,883	72,085
FEC liquids port facility	2,096	10,944	7,261	43,970
General cargo	4,654	4,599	22,289	16,495
Third party liquids port facility	5,459	3,643	17,333	11,620
Cost	(5,685)	(5,038)	(21,376)	(19,779)
General administrative expenses	(1,376)	(1,987)	(5,375)	(6,537)
Depletion, depreciation and amortization	(1,233)	(2,013)	(5,617)	(4,924)
Impairment	—	(145)	—	(145)
Restructuring, severance and other costs	(1,116)	(400)	(2,229)	(978)
Puerto Bahia income from operations	**2,799**	**9,603**	**12,286**	**39,722**
Share of Income from associates - ODL	12,135	9,751	42,043	38,033
Segment income	**14,934**	**19,354**	**54,329**	**77,755**
Segment cash flow from operations activities	**12,796**	**21,787**	**46,898**	**84,304**

The Company's Midstream Colombia Segment reported income from operations for the three months and year ended December 31, 2022 was $14.9 million and $54.3 million, respectively, compared with $19.4 million and $77.8 million in the same periods of 2021, which include Frontera Energy Colombia AG's ("**Frontera Colombia**") liquids terminal take or pay which expired in December 2021. For the year ended 2022, revenues from third party liquids and general cargo through Puerto Bahia was $39.6 million, up 41% compared to $28.1 million in 2021.

Cash provided by operating activities of the Midstream Colombia Segment for three months and year ended December 31, 2022 was $12.8 million and $46.9 million, respectively, and $21.8 million and $84.3 million, respectively, compared to the same periods of 2021, with the decrease primarily due to the finalization of a take-or-pay contract with Frontera Colombia in December 2021.

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 aggregate cash consideration of approximately $47.4 million, which is payable to the non-controlling shareholders in installments, with an upfront payment of $18.0 million and the remaining installments payable until the end of 2023. As at December 31, 2022, total cash of $36.1 million was paid. For further information refer to the Annual Financial Statements in the "Consolidated Statements of Changes in Equity" on page 5.

For the year ended December 31, 2022, ODL generated $215.1 million of EBITDA and $120.1 million of net income. ODL results are consolidated in the Company's Financial Statements through the equity method, for that reason, the Company's EBITDA is not affected. The income statement and key balance sheet information from ODL is as follows:

	Three months ended December 31		Year ended December 31	
($M)	**2022**	**2021**	**2022**	**2021**
Revenue	74,702	61,652	268,040	242,056
FEC revenue (billed units)	6,977	6,030	23,314	27,523
Third party liquids port facility	67,725	55,622	244,727	214,533
Cost	(9,329)	(10,255)	(33,541)	(35,031)
General administrative expenses	(4,204)	(2,986)	(14,329)	(11,120)
Depletion, depreciation and amortization	(6,122)	(7,753)	(29,666)	(31,834)
Other non-operating expense	(1,083)	(715)	(5,054)	(2,945)
Income Tax	(19,293)	(12,085)	(65,324)	(52,462)
ODL Net Income	**34,672**	**27,858**	**120,126**	**108,665**

($M)	Three months ended December 31 2022	Three months ended December 31 2021	Year ended December 31 2022	Year ended December 31 2021
ODL debt	37,368	47,877	37,368	47,877
ODL cash and cash equivalents	65,004	71,299	65,004	71,299

The following table shows the volumes pumped per injection point:

(bbl/d)	Three months ended December 31 2022	Three months ended December 31 2021	Year ended December 31 2022	Year ended December 31 2021
At Rubiales Station	150,634	136,699	140,393	134,997
At Jagüey and Palmeras Station	72,221	66,595	72,666	60,683
Total	**222,855**	**203,294**	**213,059**	**195,680**

The following table shows the volumes received per block:

(bbl/d)	Three months ended December 31 2022	Three months ended December 31 2021	Year ended December 31 2022	Year ended December 31 2021
Rubiales	104,407	99,839	100,046	100,626
Quifa	27,691	27,751	27,235	26,570
CPE-6	3,188	1,944	1,866	1,740
Other block	82,872	66,678	78,633	61,078
Total	**218,158**	**196,212**	**207,780**	**190,014**

For the year ended December 31, 2022, the Company recognized $42.0 million as its share of income from ODL, which was $4.0 million higher than the same period of 2021, primarily due to the impact of foreign exchange fluctuations. During the year ended December 31, 2022, the Company recognized gross dividends of $40.5 million (2021: $41.6 million) and a return of capital of $19.7 million (2021: $4.2 million).

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia, which consists of a hydrocarbon terminal and a general cargo terminal adjacent to the Bocachica access channel of the Cartagena Bay, and is strategically located near the Cartagena Refinery. On December 23, 2021, the Company increased its ownership in Puerto Bahia to 96.55%, through the conversion of certain debt held by the Company's subsidiaries, Frontera Bahia, Infrastructure Ventures Inc. ("**IVI**"), and Frontera Colombia into preferred shares with voting rights, and further increased its ownership in Puerto Bahia to 99.80%, through the conversion of certain debt held by Frontera Bahia, IVI and Frontera Colombia into ordinary shares, on December 27, 2022.

The multipurpose port facility has a total area of 155 hectares, Puerto Bahia´s segment income from operations is mainly generated from services contracts in the liquid terminal with capacity of 2,672,000 barrels, and roll-on/roll-off ("**RORO**") services in the general cargo terminal.

The following table shows throughput at Frontera´s liquid port facility at Puerto Bahia:

(bbl/d)	Three months ended December 31 2022	Three months ended December 31 2021	Year ended December 31 2022	Year ended December 31 2021
FEC volumes	13,575	31,810	13,292	25,690
Third party volumes	53,142	2,447	49,130	21,758
Total	**66,717**	**34,257**	**62,422**	**47,448**

The following table shows the roll on/roll off and the bulk break units at Frontera´s general cargo port facility at Puerto Bahia:

(units - tons/m3)	Three months ended December 31 2022	Three months ended December 31 2021	Year ended December 31 2022	Year ended December 31 2021
RORO (units) (1)	35,596	26,864	133,736	83,438
Break Bulk Volumes (Tons/m3) (2)	17,291	21,100	103,378	82,515

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

For the year ended December 31, 2022, Puerto Bahia has generated $12.3 million of segment income from operations and $20.1 million of EBITDA, which was $27.4 million and $25.5 million respectively, lower compared to the same period of 2021, primarily due to the finalization of a take-or-pay contract with Frontera Colombia in December 2021. Today, over 80% of Puerto Bahia's EBITDA is generated from third parties.

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. Operating EBITDA for the full year 2021 was revised to reflect this change, resulting in an increase of $5.0 million from what was previously reported by the Company prior to the three and six months ended June 30, 2022.

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

	Three months ended December 31		Year ended December 31	
($M)	2022	2021	2022	2021
Net income[1]	197,796	629,376	286,615	628,133
Finance income	(2,323)	(30)	(5,505)	(5,362)
Finance expenses	14,239	11,768	52,991	51,822
Income tax expense (recovery)	68,599	(36,118)	249,275	1,039
Depletion, depreciation and amortization	49,198	20,121	195,419	126,692
Recovery of impairment, recovery of asset retirement obligation and others	(207,895)	(562,520)	(206,737)	(565,523)
Costs under terminated pipeline contracts	—	(4,386)	—	(4,386)
Post-termination obligation	5,229	322	12,299	4,980
Share-based compensation non-cash portion	3,213	2,973	7,777	6,695
Restructuring, severance and other costs	2,624	1,746	4,463	4,616
Share of income from associates	(12,135)	(9,751)	(42,043)	(38,033)
Foreign exchange loss	28,230	11,128	76,413	35,510
Other loss (income)	5,381	(14,788)	10,800	(1,435)
Unrealized gain on risk management contracts	(6,600)	(4,530)	(4,310)	(7,213)
Non-controlling interests	(562)	(265)	4,420	7,933
Loss on extinguishment of debt	—	—	—	29,112
Reclassification of currency translation adjustments	—	103,599	—	103,599
Operating EBITDA	**144,994**	**148,645**	**641,877**	**378,179**

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 a company to invest in capital assets. This financial measure considers oil and gas properties, plant and equipment, infrastructure, exploration and evaluation assets.

Net Sales

Net sales is a non-IFRS financial measure that adjusts revenue to include realized gains and losses from risk management contracts while removing the cost of dilution activities, including 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 risk management activities. The deduction for dilution costs and cost of purchases is helpful to understand the Company's sales performance based on the net realized proceeds from its own production net of dilution, the cost of which is partially recovered when the blended product is sold. Net sales also exclude sales from port services, as it is not considered part of the oil and gas segment. Refer to the reconciliation in the "Sales" section on page 13.

Operating Netback 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. Refer to the reconciliation in the "Operating Netback" section on page 12.

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 cost. 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 December 31		Year ended December 31	
	2022	2021	2022	2021
Oil and gas sales ($M) [1]	326,531	306,701	1,325,845	898,518
(-) Cost of purchases ($M) [2]	(64,746)	(37,176)	(216,243)	(82,725)
Oil and gas sales, net of purchases ($M)	**261,785**	**269,525**	**1,109,602**	**815,793**
Sales volumes, net of purchases - (boe)	3,157,716	3,588,117	12,096,465	12,259,620
Oil and gas sales, net of purchases ($/boe)	82.90	75.12	91.73	66.54

1. Excludes sales from port services as they are not part of the oil and gas segment. For further information, refer to the “Midstream Activities” section on page 22.
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 December 31		Year ended December 31	
	2022	2021	2022	2021
Oil sales ($M)	257,720	267,743	1,093,066	808,493
Conventional natural gas sales ($M)	4,065	1,782	16,536	7,300
Oil and gas sales, net of purchases ($M) [1]	**261,785**	**269,525**	**1,109,602**	**815,793**
Sales volumes, net of purchases - (bbl)	3,003,102	3,512,293	11,456,143	11,938,207
Conventional natural gas sales volumes - (mcf)	881,402	431,963	3,655,102	1,831,952
Realized oil price, net of purchases ($/bbl)	85.82	76.23	95.42	67.72
Realized conventional natural gas price ($/mcf)	4.61	4.12	4.52	3.98

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 risk management contracts less royalties and dilution costs). Net sales realized price per boe is a non-IFRS ratio which is calculated dividing each component by total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2022	2021	2022	2021
Oil and gas sales, net of purchases ($M) [1]	261,785	269,525	1,109,602	815,793
(-) Realized loss on risk management contracts ($M)	(4,182)	(6,692)	(14,733)	(49,119)
(-) Royalties ($M)	(19,076)	(12,974)	(94,709)	(32,572)
(-) Dilution costs ($M)	(235)	(368)	(1,132)	(8,773)
Net sales ($M)	**238,292**	**249,491**	**999,028**	**725,329**
Sales volumes, net of purchases - (boe)	3,157,716	3,588,117	12,096,465	12,259,620
Oil and gas sales, net of purchases ($/boe)	82.90	75.12	91.73	66.54
Realized (loss) gain on risk management contracts [2]	(1.32)	(1.87)	(1.22)	(4.01)
Royalties ($/boe) [2]	(6.04)	(3.62)	(7.83)	(2.66)
Dilution costs ($/boe) [2]	(0.07)	(0.10)	(0.09)	(0.72)
Net sales realized price ($/boe)	**75.47**	**69.53**	**82.59**	**59.15**

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

Supplementary Financial Measures

Production cost per boe

Production costs mainly includes lifting costs, activities developed in the blocks, and processes to put the crude oil and gas in sales condition. Production cost per boe is a supplementary financial measure that is calculated using production cost divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2022	**2021**	**2022**	**2021**
Production costs ($M)	45,562	45,137	186,539	158,252
Production (boe)	3,846,152	3,551,660	15,104,430	13,803,205
Production costs ($/boe)	11.85	12.71	12.35	11.46

Transportation cost per boe

Transportation costs includes all commercial and logistics costs associated with the sale of produced crude oil and gas such as trucking and pipeline. Transportation cost per boe is a supplementary financial measure that is calculated using transportation cost divided by net production after royalties. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2022	**2021**	**2022**	**2021**
Transportation costs ($M)	35,749	29,225	137,852	132,029
Net production (boe)	3,380,908	3,239,504	13,176,135	12,662,215
Transportation costs ($/boe)	10.57	9.02	10.46	10.43

Realized (loss) gain on risk management contracts per boe

Realized (loss) gain on risk management contracts includes the gain or loss during the period, as a result of the Company´s exposure in derivative contracts. Realized (loss) gain on 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.

Dilution costs per boe

Dilution costs includes all costs associated with the dilution services. Dilution costs per boe is a supplementary financial measure that is calculated using the dilution costs divided by total sales volumes, net of purchases.

NCIB weighted-average price per share

Weighted-average price per share under the NCIB is a supplementary financial measure that corresponds to the weighted-average price of shares purchased under the 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 sum 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.

6. LIQUIDITY AND CAPITAL RESOURCES

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

- capital expenditures for exploration, production and development, including growth plans;
- costs and expenses relating to operations, commitments and existing contingencies;
- debt service requirements relating to existing and future debt; and
- enhancing shareholder returns through share repurchases.

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 December 31, 2022, the Company had a total cash balance of $313.0 million (including $23.2 million in restricted cash), which is $7.8 million lower than December 31, 2021. For the year ended December 31, 2022, the Company generated $620.5 million of cash from operations, which were used to fund cash outflows of $383.3 million for capital expenditures and other investing activities. For the year ended December 31, 2022, financing activities generated net outflows of $193.6 million as a result of $91.4 million of Common Shares purchased under the SIB (as defined below) and the NCIB, $45.1 million of 2025 Puerto Bahia Debt payments and PetroSud Debt (as defined below) payments, $43.5 million of interest and other financing charges, $8.3 million of dividends paid to non-controlling interests and $5.3 million in lease payments. As consequence, the net working capital(3) deficit was increase to $109.6 million compared to a deficit of $78.9 million at year-end 2021.

Since 2020, the Company's consolidated net working capital position changed to a deficit due to the acquisition of control in IVI, which resulted in the consolidation of the 2025 Puerto Bahia Debt ($103.1 million as of December 31, 2022), which was classified as a current liability (for further information on the 2025 Puerto Bahia Debt, refer to page 31 hereof and Note 18 of the Annual Financial Statements). 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 December 31, 2022, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the 2025 Puerto Bahia Debt. 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, typically during the third quarter, and can be satisfied through additional allocations of restricted cash, designation of letters of credit, or a combination of both. As of December 31, 2022, the Company's restricted cash position was $23.2 million, a decrease of $40.1 million from December 31, 2021, primarily due to restricted cash being released from (i) The Puerto Bahia Debt Service Reserve Account ("**DSRA**") used for Debt Service payment on December 15, 2022 for $24.7 million, (ii) replacement of abandonment funds with letters of credit of $7.9 million, and (iii) foreign exchange fluctuations.

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 36.

[3] Capital management measure (as defined in NI 52-112). Refer to the "Non-IFRS and Other Financial Measures" section on page 25.

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 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 and are guaranteed by the Company's principal subsidiaries, Frontera Colombia and Frontera Energy Guyana Corp. ("**Frontera Guyana**"). 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 December 31, 2022, the Company is in compliance with all such covenants.

Pursuant to requirements under the indenture governing the 2028 Unsecured Notes (the "**Indenture**"), the Company reports consolidated total indebtedness of $407,808,000 as of December 31, 2022, and for the twelve months ended as of December 31, 2022, consolidated adjusted EBITDA of $635,825,000 and consolidated interest expense of $32,419,000.

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 December 31 2022**
Long-term debt (1)	$ 405,363
Total lease liabilities (2)	2,616
Risk management asset, net (3)	(171)
Consolidated Total Indebtedness	**407,808**
(-) Cash and Cash Equivalents (4)	(229,274)
(=) Net Debt	**$ 178,534**

1. Excludes $103.1 million of long-term debt attributable to the Unrestricted Subsidiaries.
2. Excludes $0.5 million of lease liabilities attributable to the Unrestricted Subsidiaries.
3. Excludes $1.1 million of risk management assets attributable to the Unrestricted Subsidiaries.
4. Includes cash and cash equivalents attributable to the guarantors (Frontera Guyana and Frontera Colombia) and the borrower (the Company) according to the Indenture.

Puerto Bahia Secured Syndicated Credit Agreement

During the third quarter of 2020, the Company acquired control of IVI which at the time of acquisition held 99.9% of Puerto Bahia.

In October 2013, Puerto Bahia entered into a credit agreement with a syndicate of lenders for a $370 million debt facility, which matures in June 2025, for the construction and development of the port (the "**2025 Puerto Bahia Debt**"). During the course of 2018, 2019 and 2020, the lenders gave notices stating that Puerto Bahia is in breach of various loan covenants but did not accelerate the loan. As a result, the total amount outstanding under the 2025 Puerto Bahia Debt is presented as a current liability in accordance with IAS 1 "**Presentation of Financial Statements**". The 2025 Puerto Bahia Debt bears interest at 6-month LIBOR plus 5% which is payable semi-annually, is secured by substantially all the assets and shares of Puerto Bahia, is non-recourse to the Company and it has no impact on the Company's financial covenants under the 2028 Unsecured Notes. As at December 31, 2022, the 2025 Puerto Bahia Debt outstanding amount is $103.1 million.

The ability of the Company to remedy the breaches of the loan covenants depends on a number of variables, many of which are outside the Company's control. If the 2025 Puerto Bahia Debt were accelerated, the Company could pursue various options, including, but it is not obligated to, providing further support to Puerto Bahia. The Company is currently exploring refinancing alternatives, but there can be no assurance that a refinancing will be completed.

As part of the agreements for the banks' loan to fund the construction of Puerto Bahia, the Company entered into the ECA on October 4, 2013. Under the ECA, the Company and IVI agreed jointly and severally to cause contributions (via debt or equity) to Puerto Bahia up to the aggregate amount of $130.0 million (the "**ECA Loans**"), which the Company has fully disbursed. Amounts under the ECA were used to the repayment of principal and interest on the 2025 Puerto Bahia Debt. As of December 31, 2012, the Company had converted the $98.3 million in ECA debt Loans into shares of Puerto Bahia. All intercompany balances and transactions between the Company and IVI are eliminated as part of the consolidation of the Consolidated Financial Statement.

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 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 with a maturity date in December 2023. The PetroSud Debt bears interest at 3-month LIBOR plus 4.95%, 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 $2.0 million. As at December 31, 2022, the outstanding amount under the PetroSud Debt is $12.8 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 December 31, 2022, PetroSud is in compliance with all such covenants.

Letters of Credit

The Company has various uncommitted bilateral letters of credit lines. As of December 31, 2022, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $104.1 million (total credit lines of $118.4 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 S.A., to finance the construction and commissioning of a solar plant project at the CPE-6 block (the "**Solar Plant Debt**"). The financing is denominated in COP, in an amount equivalent to US$5.3 million and with 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(1) +5.75%, payable monthly. As of December 31, 2022, no disbursements have been made under this financing.

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

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at December 31, 2022, undiscounted by calendar year, are presented below:

As at December 31, 2022 ($M)	2023	2024	2025	2026	2027	2028 and Beyond	Total
Financial obligations							
2028 Unsecured Notes, principal and interest	31,500	31,500	31,500	31,500	31,500	415,750	573,250
Lease liabilities	2,747	347	190	19	—	—	3,303
2025 Puerto Bahía Debt and interest (1)	25,747	50,581	37,737	—	—	—	114,065
PetroSud Debt and interest	13,897	—	—	—	—	—	13,897
Total financial obligations	**73,891**	**82,428**	**69,427**	**31,519**	**31,500**	**415,750**	**704,515**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	71,027	71,027	35,416	—	—	—	177,470
ODL agreements	17,141	14,655	—	—	—	—	31,796
Other transportation and processing commitments	14,047	11,738	11,738	11,738	3,892	—	53,153
Exploration commitments							
Minimum work commitments (2)	84,088	31,802	53,025	—	—	5,066	173,981
Other commitments							
Operating purchases, leases and community obligations	66,692	14,605	19,815	14,610	10,661	10,004	136,387
Total Commitments	**252,995**	**143,827**	**119,994**	**26,348**	**14,553**	**15,070**	**572,787**

1. For financial reporting purposes, the 2025 Puerto Bahia Debt is classified as a current liability. Amounts shown in the table are in accordance with the repayment schedule.
2. 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. The Company, through its interests in CGX, has other exploration work commitments in Guyana (not included in the table), described below.

Guyana Commitments

As at December 31, 2022, the Company, through its 76.97% interest in CGX and directly through its working interest has exploration work commitments under the Petroleum Prospecting Licenses ("**PPLs**") for certain Guyana blocks as follows:

- Corentyne block (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 November 28, 2022, CGX and Frontera, the majority shareholder of CGX and joint venture partner of CGX (the "**Joint Venture**"), announced their continued commitment to drill the Wei-1 well and that final preparations were complete in advance of spudding the Wei-1 well. On January 23, 2023, CGX and Frontera 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.
- Demerara Block (Frontera 33% W.I. and non-operator) - On February 14, 2022, CGX and Frontera, announced that as a result of the initial positive results at the Kawa-1 exploration well on the Corentyne block, the Joint Venture would focus on the significant exploration opportunities in the Corentyne block and would not engage in drilling activities on the Demerara block in 2022. Subsequent to year end 2022, the Government of Guyana and CGX finalized a surrender deed to formalize relinquishment of the Demerara block.
- Berbice block – At year end 2022, the Company held a 47.73% indirect interest in this block through its 76.97% interest in CGX, which has an indirect interest held through its 62.0% interest in ON Energy Inc. ("**ON Energy**"), which was the holder of the PPL related to the block. On February 4, 2022, the Company, through ON Energy, notified the Ministry of Natural Resources that, given the focus on rapidly developing the Corentyne block, operational considerations and investment priorities, ON Energy would be unable to drill an exploration well on the Berbice block in 2022. Subsequent to year end 2022, the Government of Guyana and ON Energy finalized a surrender deed to formalize relinquishment of the Berbice block.

In addition, in connection with (i) a drilling contract agreement between Maersk Drilling Holdings Singapore Pte. Ltd. (now Noble Corp.) and CGX Resources Inc. ("**CGX Resources**"), the operator of the Corentyne block, for the provision of a semi-submersible drilling unit owned by Noble Corp. and associated services to drill the Joint Venture's Wei-1 well, and (ii) a 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 Noble Corp. and Schlumberger for certain obligations, in each case up to a maximum of $30.0 million and subject to a sliding scale mechanism in connection with payments made under the drilling contract with Noble Corp. or the services agreement with Schlumberger, as applicable.

As at December 31, 2022, 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 $98.3 million, which is expected to be paid in 2023.

On July 22, 2022, Frontera and CGX jointly announced that the companies entered into an agreement to amend the Joint Operating Agreement originally signed between CGX and a subsidiary of Frontera on January 30, 2019, as amended (the "**JOA Amendment**"), effectively farming into the Corentyne block and securing funding for the Joint Venture's Wei-1 well. The JOA Amendment was subject to certain conditions precedent, including approval of the TSX Venture Exchange and certain confirmations from the Government of Guyana relating to the petroleum agreement for the Corentyne block. On December 1, 2022 Frontera and CGX jointly announced that the companies had completed the JOA Amendment. As part of the JOA Amendment, CGX transferred 29.73% of its participating interest in the Corentyne block to Frontera in exchange for Frontera funding the Joint Venture's costs associated with the Wei-1 well for up to $130.0 million and up to an additional $29.0 million of certain Kawa-1 exploration well and Wei-1 Pre-Drill and other costs. In addition, CGX assigned an additional 4.94% of its participating interest in the Corentyne block to Frontera as consideration for the repayment of the outstanding principal amounts under (i) the previously announced $19.0 million convertible loan to CGX dated May 28, 2021, as amended, and (ii) the previously announced $35.0 million convertible loan to CGX dated March 10, 2022, as amended, and Frontera made a cash payment to CGX of $3.8 million. As a result of the JOA Amendment, CGX has a 32.00% participating interest and Frontera has a 68.00% participating interest in the Corentyne block.

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. The term of the pledge agreement has been amended and extended for the period from May 1, 2022, to March 31, 2023, with Ocensa, and for the period from May 1, 2022, to April 30, 2023, with Cenit.

Other Guarantees and Pledges

As part of the Company's acquisition of 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 December 31, 2022, the Company has paid and accrued a total of $15.2 million of such amounts under the agreement.

Sale of Subsidiary Maurel et Prom Colombia B.V. ("M&P")

On October 22, 2021, the Company executed and closed a sale and settlement agreement, transferring to Etablissement Maurel & Prom 49.999% of all issued and outstanding shares of M&P, which holds 100% interests in the COR-15 and Muisca blocks in Colombia. The Company received cash consideration of $1.8 million. In addition, during the period ended September 30, 2022, the Company made payments of $6.0 million related to outstanding commitments at the COR-15 block.

Contingencies

The Company is involved in various claims and litigation arising in 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 consolidated financial position, results of operations or cash flows.

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 of that barrels of crude oil had on that delivery date. In addition, Ecopetrol requested the Company to 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 has filed an appeal against the first instance ruling on March 16, 2021, and a final ruling is pending. The Company has included a liability provision of $9.3 million.

Agencia Nacional de Hidrocarburos Discussion

Since May 8, 2020, the Company has been discussing with the ANH the termination of certain exploratory contracts due to environmental, social and security restrictions in the contracted areas, which are preventing the Company from executing on exploratory commitments of $26.2 million.

On December 12, 2021, the Company informed the ANH that the outstanding commitments at the LLA-7 and LLA-55 blocks of $26.2 million were going to be executed by means of drilling exploration wells in other blocks, as provided under the recent regulation issued by the ANH (Acuerdo 10 of 2021). Currently, the Company has proposed some activities to be deducted from these commitments. Once the activities are completed and are evidence to the ANH, they will be deemed to have been fulfilled.

On December 20, 2022, the Company requested that the ANH terminate the contracts for the CAG-5 and CAG-6 blocks due to social and security restrictions in the contracted areas pursuant to a recent regulation issued by the ANH (Acuerdo 01 of 2022). The CAG-5 and CAG-6 blocks have exploration commitments for a total of $101.8 million (the Company's net share of such commitment is $53.0 million).

High-Price Clause

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

The Company and the ANH continue to review differences in interpretations for the remaining exploitation areas. The Company does not disclose the recorded provision amounts, as required by IAS 37, Provisions, Contingent Liabilities and Contingent Assets, on the grounds that this would be prejudicial to the outcome of potential future disputes with the ANH.

Puerto Bahia – Tank Construction Related Arbitration

In the course of constructing 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 up 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. The total amount claimed is $70.4 million. 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. Puerto Bahia claims damages up to $65 million.

During 2021, the CITT claim structure was amended to remove the technical claims, while concentrating on the request for the return funds drawn under the LOC. Of the approximately $68.2 million claimed by CITT, approximately $17 million corresponds to the amount delivered to Puerto Bahia through the LOC, and approximately $29.1 million corresponds to the interests on the LOC. As per Puerto Bahia's defense arguments, the interest is being erroneously calculated by CITT as they are applying a different rate from the 4% annual rate stipulated in the EPC contract and have also contravened Colombian legal provisions regarding interest calculations. Between May and June 2022, the final hearings were held, and in September 2022, Puerto Bahia filed a post-hearing brief. An arbitration award is pending.

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. A the conciliation hearing before the General Attorney Office is expected to take place in March 2023. The settlement that could result from that hearing must be approved by the courts.

Tax reviews

The Company operates in various jurisdictions and is subject to assessments by tax authorities in each of those jurisdictions, which can be complex and based on interpretations. The Company is currently in discussions with tax authorities for various assessments with respect to certain income tax deductions relating to exportation expenditures, transportation costs, VAT credits, municipal taxes, and other expenses. As at December 31, 2022, the Company has assessed a possible tax exposure of $85.4 million, (2021 $101.4 million) relating to these assessments for taxes, interest and penalties.

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 1, 2023:

	Number
Common shares	85,146,370
Deferred share units ("**DSUs**") (1)	848,187
Restricted share units ("**RSUs**") (2)	1,773,948

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 NCIB, upon the expiry of its previous NCIB (which expired on March 16, 2022), pursuant to which the Company may purchase for cancellation up to 4,787,976 of its Common Shares during the twelve-month period commencing March 17, 2022 and ending March 16, 2023, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules) as at March 7, 2022. In connection with the Company's C$65 million SIB, and as required under TSX rules, Frontera suspended share repurchases under its NCIB from June 20, 2022 (the date the SIB was announced) until August 8, 2022 (the expiry time of the SIB).

Purchases subject to the NCIB are carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc., on behalf of Frontera in accordance with an automatic share purchase plan and applicable regulatory requirements. During the three months and year ended December 31, 2022, the Company purchased a total of 983,100 and 4,197,100 Common Shares, respectively, under its NCIB (3,808,900 under its current NCIB and 388,200 under its previous NCIB). As at March 1, 2023, the Company had repurchased for cancellation a total of 4,270,100 Common Shares under its NCIB for approximately $40.9 million with an additional 517,876 Common Shares remaining available for repurchase under the NCIB. Under the prior NCIB that expired on March 16, 2022, the Company repurchased for cancellation during the twelve-month term a total of 4,243,600 Common Shares, for approximately $25.0 million.

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

	Year ended December 31
	2022
Number of Common Shares repurchased	4,197,100
Total amount of Common Shares repurchased ($M)	40,248
Weighted-average price per share ($) [1]	9.59

1. Supplementary financial measure. Refer to the "Non-IFRS and Other Financial Measures" section on page 25.

Substantial Issuer Bid

On June 24, 2022, the Company launched the SIB, pursuant to which the Company offered to purchase from shareholders for cancellation up to C$65.0 million of its outstanding Common Shares. The SIB proceeded by way of a "modified Dutch auction" procedure, with a tender price range from C$11.00 to C$13.00 per Common Share. The SIB expired on August 8, 2022.

On August 11, 2022, the Company announced that, in accordance with the terms and conditions of the SIB, the Company took up for cancellation 5,416,666 Common Shares at a price of C$12.00 per Common Share, for a total cost of $51.2 million (funded by cash, representing an aggregate purchase price of C$65 million plus transaction costs). The Common Shares taken up for cancellation under the SIB represented approximately 5.84% of the total number of the Company's issued and outstanding Common Shares as of August 8, 2022.

8. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding, commitments and transactional amounts with related parties, as at December 31, 2022 and December 31, 2021, and for the three months and year ended December 31, 2022, and 2021, respectively:

($M)		Accounts Payable	Commitments	Three Months Ended December 31	Year Ended December 31
				Purchases / Services	
ODL	2022	2,553	31,796	6,977	23,313
	2021	112	56,716	6,030	27,523

9. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives including, but not limited to: production; liquidity/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 AIF and the Annual Financial Statements, copies of which are available on SEDAR at www.sedar.com.

Significant Risk Factors

Production

The Company's operations are subject to risks that could impact oil and gas production from operations. Changes to actual or projected production levels can fluctuate based on increases or decreases in capital expenditure levels and management decisions to shut-in production. In April 2020, in response to the low oil price environment, the Company reduced capital expenditures and temporarily shut-in production from certain fields in Colombia with lower field netbacks. As a result of these actions, production levels decreased. The Company seeks to minimize the financial impact of such risks by managing capex programs to focus on economic production and focusing on maintaining reservoir management as fields are brought back online.

In addition, the Company's production levels could be impacted by operational hazards (e.g., explosion, mechanical failures), community blockades, human health issues (e.g., poisoning, viruses) and delays in critical suppliers. These risks could generate impacts on the revenue generation (deferral losses) and reputational damage related to non-compliance with the market and stakeholders expectations. As part of its risk mitigation program, the Company monitors operational risks, the social environment and community engagement to activate strategies to avoid or diminish possible impacts on total production.

Liquidity/Financial

The Company is exposed to normal financial risks inherent in the oil and natural gas industry, including liquidity risk, commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company's principal liquidity and capital resource requirements are capital expenditures for exploration and development, operating expenses, debt services and shareholder returns (such as dividends). The Company funds these requirements through current cash and working capital balances which are carefully managed to ensure that operational needs and other financial obligations are met. For further information on liquidity and capital risk mitigation see section "Liquidity and Capital Resources" on page 29.

The Company also continuously monitors opportunities to use financial instruments such as derivatives to manage exposure to fluctuations in commodity prices and interest rate. For further information see the sections "Risk Management Contracts - Brent Crude Oil" section on page 17 and "Risk Management Contracts - Interest Rate Swap (2025 Puerto Bahia Debt)" section on page 18.

The use of such financial instruments exposes the Company to risks of financial loss. These risks arise from, but are not limited to, the fluctuation in the price of the underlying asset, poor correlation between the valuation of the financial instrument and the valuation of the underlying asset being hedged, unenforceability of contracts and counterparty default.

Health, Safety and Environmental

Given the operational and technical complexity associated with the oil and gas industry, the Company is subject to health, safety and environment risks. The Company seeks to minimize these risks by measuring and monitoring health, safety and environmental standards on a continuous basis and conducting its operations in a safe and reliable manner in accordance with high safety standards. Failure to manage the risks effectively could result in potential fatalities, serious injuries, interruptions to operations, damage to assets, environmental impact or loss of license to operate. Emergency preparedness, enhanced safety protocols, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Exploration, New Business and Reserves Growth

The long-term success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas. Without the continual addition of new reserves through exploration, acquisition, or development activities, the Company's existing reserves and production therefrom will decline over time as such reserves are exploited. The Company believes it has set up appropriate mitigation measures to protect against these risks. Some of these measures include generating more efficient development plans, diversifying the Company's asset base, developing reserve development strategies, employing highly skilled employees and utilizing available technology. The Company also periodically monitors the economic viability of the execution of the exploratory activity and farm-in / farm-out concerning the oil price scenarios.

Information Security

The Company is subject to a variety of information technology and system risks as a part of its normal course operations and with a significant portion of the employee base working remotely or in a hybrid work modality. Such risks include cyber-attacks, information fraud or theft, compromise of the confidentiality, network availability and integrity of corporate information, critical infrastructure, and personal data.

Although the Company has security measures, processes and controls in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in production affectation, a loss of material and confidential information and reputation, breach of privacy laws and disruption to its business activities. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Political Risks

The Company has assets and investments across South America. As such, the Company is subject to political risks, such as changes in laws and regulations, lack of governance in areas where we operate, change in political regimes and regulatory instability. If these risks materialize, it could impact our operations, delay existing projects and/or cause higher operating costs. In order to manage these risks, the Company engages with local governments and stakeholders, has established plans for monitoring and reacting to legislative changes and continues to develop a balanced and diversified portfolio of assets in the areas where we operate.

COVID-19 Pandemic

The COVID-19 pandemic, and related government responses, have had and could continue to have a negative impact 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 remains and could impact the health and safety of the Company's employees and contractors; require the temporary suspension of operations in geographic locations in which the Company operates; create operational restrictions; delay the completion of or result in the deferral of growth and expansion projects; create counterparty credit risk; result in continued supply chain disruptions; and result in continued volatility in financial and commodity markets, including fluctuations in the price of oil and natural gas products.

In the event that the spread (or fear of spreading) of COVID-19 continues, governments may increase or extend restrictions, directives, orders or regulations that could adversely affect the Company's operations, suppliers, customers, counterparties, shippers or partners, employee health, workforce productivity, insurance premiums and coverage, and ability to advance its existing and future growth projects or carry out its ongoing business plan.

The full extent, effect and duration of such events on 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 have had, and could continue to have, a material adverse effect on the Company's business, financial condition and results of operations. Even after the COVID-19 pandemic has subsided, 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 in the Company's AIF.

Rusia-Ukraine Conflict

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-randging 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.

See the "Liquidity and Capital Resources" section on page 29 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 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 Annual Consolidated Financial Statements which are available on SEDAR at www.sedar.com.

10. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Annual Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook -Accounting. A summary of significant accounting policies applied is included in Note 3a of the Annual Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Recent accounting pronouncements of significance or potential significance are described in Note 3b of the Annual Consolidated Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the Annual Consolidated 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 Annual Consolidated Financial Statements. The Company evaluates its estimates on an ongoing basis.

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

The effect of the COVID-19 pandemic on the world economy, the impact of the Russia Ukraine conflict and the associated volatility in oil prices, could have negative impacts on the Company and has significantly increased economic uncertainty. The Company continues to monitor this rapidly changing environment and the impact on the Company's business, financial conditions and results of operations, however the duration and magnitude of these events remains unknown at this time. There may also be effects that are not currently known, as the full impact of the COVID-19 pandemic and the impact of the Russia Ukraine conflict is still uncertain. As a result, it is difficult to reliably assess the full impact this will have on the Company's business, financial conditions and results of operations which presents uncertainties and risks in management's judgments, estimates, and assumptions used in the preparation of the Annual Consolidated 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 Annual Financial Statements.

11. INTERNAL CONTROL

In accordance with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Annual Filings". This Certification requires certifying officers to certify, among other things, that they are responsible for establishing and maintaining Disclosure Controls 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 2022, Management 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 internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting, the Company will continue to monitor and mitigate the risks associated with any changes to its control environment in response to COVID-19 pandemic.

Management has evaluated the effectiveness of the Company's ICFR as at December 31, 2022.

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 December 31, 2022.

There have been no changes in the Company's ICFR during the quarter ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, its ICFR.

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

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

Based on management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and its Chief Financial Officer, concluded that the Company's DC&P were effective as at December 31, 2022.

12. 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				
					Year ended December 31	
Producing blocks in Colombia		**Q4 2022**	**Q3 2022**	**Q4 2021**	**2022**	**2021**
Heavy crude oil	(bbl/d)	18,466	16,667	18,099	17,492	17,371
Light and medium crude oil	(bbl/d)	14,876	15,267	15,721	15,421	16,046
Conventional natural gas	(mcf/d)	9,092	9,966	4,663	9,741	5,022
Natural gas liquids	(boe/d)	993	911	575	958	393
Net production Colombia	**(boe/d)**	**35,930**	**34,593**	**35,213**	**35,580**	**34,691**
Producing blocks in Ecuador						
Light and medium crude oil	(bbl/d)	819	719	—	519	—
Net production Ecuador	**(bbl/d)**	**819**	**719**	**—**	**519**	**—**
Total net production	**(boe/d)**	**36,749**	**35,312**	**35,213**	**36,099**	**34,691**

Overlift and Settlement

Overlift and settlement corresponds to a short-term imbalance between the Company's production and sales volumes. In these instances, the Company lifts barrels from the pipeline system resulting in more volumes sold than produced, which is considered "overlift." Overlift represents an obligation for the Company to deliver the equivalent future production. Settlement occurs when this production is delivered to settle the overlift liability. During overlift, the Company recognizes the sales and an equivalent cost with no margin or operating EBITDA impact during the quarter. When the overlift is settled, this expense is reversed to recognize the gross margin and operating EBITDA earned on the related sale in the period of production. Refer to the "Oil and Gas Operating Costs" section on page 14.

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.

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
COP	Colombian Pesos	**$**	U.S. dollars
C$	Canadian dollars	**$M**	Thousand U.S. dollars
MMbbl	Millions of oil barrels	**$MM**	Million U.S. dollars
MMboe	Millions of barrels of oil equivalent	**P1**	Proved reserves
Mbbl	Thousand of oil barrels	**P2**	Probable reserves
Mcf	Thousand cubic feet	**2P**	Proved reserves + Probable reserves
mcf/d	Thousand cubic feet per day		