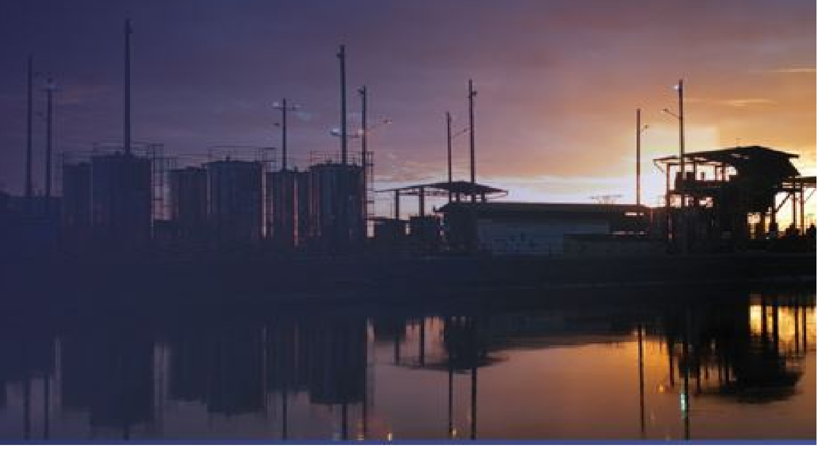
MANAGEMENT DISCUSSION & ANALYSIS

May 3, 2022
For the three months ended March 31, 2022



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*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 1610, 222 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.*

Legal Notice – Forward-Looking Information

*This Management Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Condensed Consolidated Financial Statements and related notes for the three months ended March 31, 2022 and 2021 ("**Interim Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and the Annual Information Form (**"AIF"**), have been filed with Canadian securities regulatory authorities and is 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 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 measures are described in greater detail under the heading "Non-IFRS Measures" section on page 15.*

*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 and General and Administrative expenses ("**G&A**") 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; 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, material assumptions that could cause actual results to differ materially from those anticipated in these forward-looking statements 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 contain future oriented financial information and financial outlook information (collectively, "FOFI") within the meaning of applicable Canadian securities laws. The FOFI has been prepared by management to provide an outlook of the Company's activities and results and may not be appropriate for other purposes. Management believes that the FOFI has been prepared on a reasonable basis, reflecting management's reasonable estimates and judgments; however, actual results of the Company's operations and the resulting financial outcome may vary from the amounts set forth herein. Any FOFI speaks only as of the date on which it was made, and the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or otherwise, unless required by applicable laws.

1. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q1 2022	Q4 2021	Q1 2021
Operational Results				
Heavy crude oil production	(bbl/d)	21,214	20,912	20,997
Light and medium crude oil production	(bbl/d)	17,248	16,300	18,294
Total crude oil production [1]	(bbl/d)	38,462	37,212	39,291
Conventional natural gas production [1]	(mcf/d)	9,530	4,663	5,227
Natural gas liquids [1]	(boe/d)	966	575	391
Total production [2]	(boe/d) [3]	41,100	38,605	40,599
Total inventory balance	(bbl)	1,434,111	807,061	1,183,035
Oil and gas sales, net of purchases [4]	($/boe)	90.42	75.12	58.18
Realized (loss) gain on risk management contracts	($/boe)	(1.06)	(1.87)	(3.53)
Royalties	($/boe)	(7.58)	(3.62)	(1.96)
Dilution costs	($/boe)	(0.12)	(0.10)	(2.25)
Net sales realized price [5]	($/boe)	81.66	69.53	50.44
Production costs [6]	($/boe)	(13.48)	(12.71)	(10.06)
Transportation costs [7]	($/boe)	(9.74)	(9.02)	(11.30)
Operating netback [4]	($/boe)	58.44	47.80	29.08
Financial Results				
Oil & gas sales, net of purchases	($M)	229,569	269,525	180,956
Realized (loss) gain on risk management contracts	($M)	(2,682)	(6,692)	(10,980)
Royalties	($M)	(19,244)	(12,974)	(6,110)
Dilution costs	($M)	(298)	(368)	(6,983)
Net sales [4]	($M)	207,345	249,491	156,883
Net income (loss) [8]	($M)	102,228	629,376	(14,126)
Per share – basic	($)	1.08	6.60	(0.14)
Per share – diluted	($)	1.05	6.40	(0.14)
General and administrative	($M)	14,656	12,144	13,202
Operating EBITDA [4]	($M)	132,770	148,323	69,158
Cash provided by operating activities	($M)	114,980	113,482	47,393
Capital expenditures	($M)	113,545	135,458	14,365
Cash and cash equivalents – unrestricted	($M)	257,373	257,504	248,237
Restricted cash short and long-term	($M)	66,146	63,321	161,230
Total cash	($M)	323,519	320,825	409,467
Total debt and lease liabilities	($M)	558,281	560,135	534,656
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [4][9]	($M)	410,161	416,883	361,699
Net debt (excluding Unrestricted Subsidiaries) [4][9]	($M)	199,303	207,578	139,327

1. Reference to heavy crude oil, light and medium crude oil combined, natural gas liquids, or conventional natural gas production in the above table and elsewhere in this MD&A refer to the heavy crude oil, light and medium crude oil combined, natural gas liquids, and conventional natural gas, respectively, product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities.*
2. Represents W.I. production before royalties. Refer to the "Further Disclosures" section on page 24.
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 24.
4. Non-IFRS financial measures. Refer to the "Non-IFRS Measures" section on page 15. This section also includes a description and details for all per boe metrics included in operating netback.
5. Per boe is calculated using sales volumes, exclude volumes purchased from third parties.
6. Per boe is calculated using production.
7. Per boe is calculated using net production after royalties.
8. Net income (loss) attributable to equity holders of the Company.
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., Frontera Bahía Holding Ltd.("**Frontera Bahía**"), including its subsidiary Sociedad Portuaria Puerto Bahía S.A. ("**Puerto Bahia**").

Performance Highlights

First Quarter of 2022

Frontera continued to deliver strong performance results in the first quarter of 2022, as a result of the substantive improvements made to the business since 2020 to streamline operations, implement efficiencies and capitalize on stronger oil prices. These initiatives have resulted in higher cash flows from operating activities and operating EBITDA generated on a lower transportation and dilution costs compared to the first quarter of 2021. These actions helped the Company's liquidity position, ending the first quarter of 2022 with a total cash position of $323.5 million, including $66.1 million of restricted cash, compared with a total cash position of $409.5 million, including $161.2 million of restricted cash, in the first quarter of 2021.

Operationally, the Company executed $113.5 million in capital expenditures in the first quarter primarily in support of exploration activity at the Kawa-1 exploration well offshore Guyana and, discovery of light and medium crude oil in the Jandaya-1 and Tui-1 exploration wells in Ecuador, and development drilling which contributed to 6% production increase in the Company's base Colombia operations compared with fourth quarter 2021.

During the quarter, Frontera began integrating the PetroSud assets into its operations. In light of higher oil prices, the Company is currently reviewing opportunities for additional capital expenditures that may drive increased production in the second half of the year. Frontera expects increased operational momentum throughout the rest of the year which will drive higher production and profitability in subsequent quarters.

During the quarter, the Company renewed its NCIB program for the purchase of up to 10% of our public float and is reviewing other opportunities to enhance shareholder returns. As of May 2, 2022, Frontera has purchased for cancellation 1,246,400 common shares at a volume weighted average price of C$14.39 per share, excluding brokerage fees. Under the Company's previous NCIB that expired on March 16, 2022, Frontera purchased for cancellation 4,243,600 common shares at a volume weighted average price of C$7.38 per share, excluding brokerage fees.

On March 15, 2022, Frontera was recognized for the second straight year by Ethisphere, a global leader in defining and advancing the standards of ethical business practices, as one of the 2022 World's Most Ethical Companies. Frontera is the only honouree in the Oil and Gas, Renewables category. In 2022, 136 honourees were recognized spanning 22 countries and 46 industries. Additionally, Frontera was certified by Great Place to Work ("**GPTW**") as the only oil and gas company with an outstanding work environment. Frontera was also recognized as one of the best places to work for women in Colombia among the 2021 GPTW ranking.

Financial and Operational Results

- Production averaged 41,100 boe/d in the first quarter of 2022 (consisting of 21,214 bbl/d of heavy crude oil, 17,248 bbl/d of light and medium crude oil, 9,530 Mcf/d of conventional natural gas and 966 boe/d of natural gas liquids), compared with 38,605 boe/d in the prior quarter (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), and 40,599 boe/d in the first quarter of 2021 (consisting of 20,997 bbl/d of heavy crude oil, 18,294 bbl/d of light and medium crude oil, 5,227 Mcf/d of conventional natural gas and 391 boe/d of natural gas liquids).
- Cash provided by operating activities was $115.0 million in the first quarter of 2022, compared with $113.5 million in the prior quarter and $47.4 million in the first quarter of 2021. The Company reported a total cash position of $323.5 million, including $66.1 million of restricted cash, as at March 31, 2022, compared with a total cash position of $409.5 million, including $161.2 million of restricted cash, as at March 31, 2021.
- Net income was $102.2 million ($1.08/share) in the first quarter of 2022, compared with net income of $629.4 million ($6.60/share) in the prior quarter and net loss of $14.1 million ($0.14/share) in the first quarter of 2021.
- Capital expenditures were $113.5 million in the first quarter of 2022, compared with $135.5 million in the prior quarter and $14.4 million in the first quarter of 2021.
- Operating EBITDA was $132.8 million in the first quarter of 2022, compared with $148.3 million in the prior quarter and $69.2 million in the first quarter of 2021.
- Operating netback was $58.44/boe in the first quarter of 2022, compared with $47.80/boe in the prior quarter and $29.08/boe in the first quarter of 2021.

2. GUIDANCE

The following table reports the Company´s full year 2022 guidance metrics as released on March 2, 2022.

		2022	
		Guidance [1]	Q1 Actual
Average production	boe/d	40,000 - 43,000	41,100
Production costs	$/boe	11.00 - 12.00	13.48
Transportation costs	$/boe	10.00 - 11.00	9.74
Operating EBITDA at $70/bbl	$MM	375 - 425	
Operating EBITDA at $80/bbl	$MM	475 - 525	132.8
Operating EBITDA at $90/bbl	$MM	575 - 625	
Development Drilling	$MM	130 - 140	36.9
Development Facilities	$MM	40 - 50	6.0
Colombia and Ecuador Exploration	$MM	50 - 60	10.2
Other	$MM	5	7.0
Total Colombia and Ecuador Upstream Capital Expenditures	$MM	225 - 255	60.0
Guyana Exploration	$MM	110 - 130	52.0
Guyana Port Project	$MM	5 - 10	1.6
Capital Expenditures [2]	$MM	340 - 395	113.5

1. Current Guidance calculated at foreign exchange rate of 3,750 COP to 1 USD.
2. Capital Expenditures excludes decommissioning cost of $10 million.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company’s operations in Colombia and Ecuador. Refer to the “Further Disclosures” section on page 24 for details of the Company’s net production.

		Production		
Producing blocks in Colombia		**Q1 2022**	**Q4 2021**	**Q1 2021**
Heavy crude oil	(bbl/d)	21,214	20,912	20,997
Light and medium crude oil	(bbl/d)	16,969	16,300	18,294
Conventional natural gas	(mcf/d)	9,530	4,663	5,227
Natural gas liquids	(boe/d)	966	575	391
Total production Colombia	**(boe/d)**	**40,821**	**38,605**	**40,599**
Producing blocks in Ecuador				
Light and medium crude oil	(bbl/d)	279	—	—
Total production Ecuador	**(bbl/d)**	**279**	**—**	**—**
Total production	**(boe/d)**	**41,100**	**38,605**	**40,599**

Colombia

Production in Colombia for the three months ended March 31, 2022, increased by 6% compared to the prior quarter mainly due to the acquisition by the Company of 100% of the shares of Petroleos Sud Americanos S.A. (“**PetroSud**”) on December 30, 2021, which resulted in the addition of 1,226 boe/d during the first quarter of 2022 (consisting of 4,874 Mcf/d of conventional natural gas, 324 bbl/d of light and medium crude oil, and 47 bbl/d of natural gas liquids). In addition, organic growth across the portfolio resulted from an increase in natural gas liquids, mainly in the VIM-1 block, light and medium crude oil, mainly in the Guatiquia block, and heavy crude oil, mainly in CPE-6 block, due to development wells drilled that occurred during second half of 2021.

In comparison to the first quarter of 2021, production was 1% higher, mainly due to the acquisition of PetroSud, as detailed above. In addition, during the first quarter of 2022, production in the natural gas liquids and heavy crude oil categories increased, mainly in the VIM-1 and CPE-6 blocks, respectively, which 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 ended March 31, 2022, was 279 bbl/d of light and medium crude oil. Production in Ecuador started during the first quarter of 2022 after recent discoveries at the Jandaya and Tui-1 wells in the Perico exploration block.

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.

		Q1 2022	Q4 2021	Q1 2021
Production	(boe/d)	**41,100**	**38,605**	**40,599**
Royalties in-kind Colombia	(boe/d)	(4,334)	(3,392)	(2,762)
Royalties in-kind Ecuador (1)	(boe/d)	(98)	—	—
Net production	(boe/d)	**36,668**	**35,213**	**37,837**
Oil inventory (build) draw	(boe/d)	(6,967)	6,697	(751)
(Settlement) overlift	(boe/d)	(10)	(1)	(640)
Volumes purchased	(boe/d)	3,990	3,861	577
Other inventory movements (2)	(boe/d)	(1,704)	(2,201)	(1,785)
Sales volumes	(boe/d)	**31,977**	**43,569**	**35,238**
Sale of volumes purchased	(boe/d)	(3,766)	(4,568)	(683)
Sales volumes, net of purchases	(boe/d)	**28,211**	**39,001**	**34,555**
Oil sales volumes	(bbl/d)	26,500	38,177	33,648
Conventional natural gas sales volumes	(mcf/d)	9,753	4,697	5,170
Total oil and conventional natural gas sales volumes, net of purchases	(boe/d)	**28,211**	**39,001**	**34,555**
Inventory balance				
Colombia	(bbl)	937,583	326,861	602,536
Peru	(bbl)	480,200	480,200	580,499
Ecuador	(bbl)	16,328	—	—
Inventory ending balance	**(bbl)**	**1,434,111**	**807,061**	**1,183,035**

1. The Company reported 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 March 31, 2022, decreased by 28% compared with the prior quarter, mainly due to the timing of cargo sales during the fourth quarter impacting volumes sold in Colombia and an increase in inventory which will be sold in subsequent quarters according to nomination and scheduling of cargos. In comparison to the first quarter of 2021, sales volumes, net of purchases, decreased by 18%, due to volumes sold in Peru during 2021. Production from Ecuador is being delivered to a nearby access point on Ecuador's main pipeline system for sale to export markets, and the first parcel from this production will be exported in May.

Colombia Royalties PAP

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

		Q1 2022	Q4 2021	Q1 2021
PAP in cash	(bbl/d)	371	273	201
PAP in kind	(bbl/d)	2,027	1,683	19
PAP	**(bbl/d)**	2,398	1,956	220
% Production		**5.8 %**	**5.1 %**	**0.5 %**

For the three months ended March 31, 2022, PAP increased compared with both the same period of 2021 and the prior quarter, primarily due to higher WTI oil benchmark price.

Realized and Reference Prices

		Q1 2022	Q4 2021	Q1 2021
Reference price				
Brent	($/bbl)	97.90	79.66	61.32
Average realized prices				
Realized oil price, net of purchases	($/bbl)	94.67	74.94	59.15
Realized conventional natural gas price	($/mcf)	4.32	4.12	3.96
Net sales realized price				
Oil and gas sales, net of purchases	($/boe)	90.42	75.12	58.18
Realized loss on risk management contracts[1]	($/boe)	(1.06)	(1.87)	(3.53)
Royalties	($/boe)	(7.58)	(3.62)	(1.96)
Dilution costs [2]	($/boe)	(0.12)	(0.10)	(2.25)
Net sales realized price	**($/boe)**	**81.66**	**69.53**	**50.44**

1. Includes put premiums paid for the position expired during the period.
2. 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 Quifa), 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 price during the three months ended March 31, 2022, increased by 60%, compared to the same period of 2021. In comparison to the fourth quarter of 2021, the average Brent benchmark oil price increased by 23%. The increase in crude oil prices was mostly attributable to three factors: (i) a market that is undersupplied due to the low levels of the inventories below the five years average, (ii) reduction in OPEC's spare capacity, and (iii) the Russia Ukraine conflict, which is also affecting the global crude oil supply. Despite the concerns regarding the COVID-19 pandemic, including new variants that emerged, demand continued to outperform supply despite the high crude oil prices.

For the three months ended March 31, 2022, the Company's net sales realized price was $81.66/boe, an increase of 62% compared to the same period of 2021. The increase is mainly the result of higher Brent benchmark price, better differential compared with previous quarter, lower loss on risk management contracts (first quarter 2022 only includes premiums paid for the position expired during the period), and reduction in dilution costs due to replacement of the dilution service by volumes purchased, partially offset by higher cash royalties resulting from the oil price increase, and higher differentials when compared to the first quarter of 2021.

Operating Netback

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

	Q1 2022		Q4 2021		Q1 2021	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price [1] [2]	207,345	81.66	249,491	69.53	156,883	50.44
Production costs [3]	(49,861)	(13.48)	(45,137)	(12.71)	(36,755)	(10.06)
Transportation costs [4]	(32,153)	(9.74)	(29,225)	(9.02)	(38,473)	(11.30)
Operating Netback [5]	**125,331**	**58.44**	**175,129**	**47.80**	**81,655**	**29.08**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases [2] [6]		28,211		39,001		34,555
Production [7]		41,100		38,605		40,599
Net production [8]		36,668		35,213		37,837

1. Per boe is calculated using produced sales volumes. Refer to "Realized and Reference Prices" on page 6.
2. Prior period figures are different compared with those previously reported as a result of the change in the treatment of purchased volumes and cost of purchases in accordance with the current operating netback approach. Refer to the "Non-IFRS Measures" section on page 15 for further details.
3. Per boe is calculated using production. Prior period figures are different compared with those previously reported as a result of a reclassification from production cost to transportation cost. Refer to the "Selected Quarterly Information" section on page 13 for further details.
4. Per boe is calculated using net production after royalties.
5. Refer to the "Non-IFRS Measures" section on page 15 for details and a description of the operating netback calculation.
6. Sales volumes, net of purchases exclude sales of third-party volumes.
7. Refer to the "Production" section on page 4.
8. Refer to the "Further Disclosures" section on page 24.

Operating netback for the first quarter of 2022 was $58.44/boe, compared to $29.08/boe in the same quarter of 2021. The increase was primarily due to higher net sales realized price, and lower transportation cost per boe of $1.56/boe, primarily due to no barrels being transported in Peru during the first quarter of 2022, partially offset by, higher production costs due to increased energy costs, additional well services and maintenance costs.

In comparison to the fourth quarter of 2021, operating netback for the first quarter of 2022 increased from $47.80/boe to $58.44/boe, primarily due to higher net sales realized price, partially offset by higher production costs mainly due to an increase in energy costs, additional well services, and higher transportation costs due to the one-time prepaid services recorded as lower transportation costs during the fourth quarter of 2021 after the implementation of the conciliation agreement (the "**Conciliation Agreement**" between Frontera, Cenit Transporte y Logistica de Hidrocarburos S.A.S.("**Cenit**") and Bicentenario de Colombia S.A.S. ("**Bicentenario**") (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 (the "**2021 Annual Consolidated Financial Statements**").

Sales

	Three months ended March 31	
($M)	**2022**	**2021**
Oil and gas sales, net of purchases [1]	229,569	180,956
Realized loss on risk management contracts[2]	(2,682)	(10,980)
Royalties	(19,244)	(6,110)
Dilution cost	(298)	(6,983)
Net sales[3]	**207,345**	**156,883**
$/boe using sales volumes	81.66	50.44

1. "Oil and gas sales, net of purchases" is a non-IFRS measure and includes crude oil and conventional natural gas sales, net of cost of third-party volumes purchased. For further detail refer to the "Non-IFRS Measures" section on page 15.
2. Includes put premiums paid for the position expired during the period.
3. "Net sales" is a non-IFRS measure. For further detail refer to the "Non-IFRS Measures" section on page 15..

Oil and gas sales, net of purchases, increased by $48.6 million for the three months ended March 31, 2022, compared to the same period of 2021, mainly due to higher Brent benchmark oil prices (refer to the "Realized and Reference Prices" section on page 6 for further detail on changes in prices).

Net sales for the three months ended March 31, 2022, increased by $50.5 million, compared with the same period of 2021. The following table describes the various factors that impacted net sales:

	Three months ended March 31
($M)	**2022-2021**
Net sales for the period ended March 31, 2021	156,883
Increased due to 55% higher oil and gas price	100,238
Decrease due to lower volumes sold of 6,344 boe/d or 18%	(51,625)
Decrease in realized loss on risk management contracts	8,298
Decrease in dilution costs	6,685
Increase in royalties	(13,134)
Net sales for the period ended March 31, 2022	**207,345**

Oil and Gas Operating Costs

	Three months ended March 31	
($M)	**2022**	**2021**
Production costs	49,861	36,755
Transportation costs	32,153	38,473
Cost of purchases [1]	35,422	4,004
Dilution costs	298	6,983
Post-termination obligation	228	—
(Settlement) overlift	(22)	(2,659)
Inventory valuation	(18,572)	3,228
Total oil and gas operating costs	**99,368**	**86,784**

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 the Oil and gas sales, net of purchases. For further detail refer to the "Non-IFRS Measures" section on page 15.

For the three months ended March 31, 2022, total oil and gas operating costs increased by 15% compared to the same period of 2021. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs increased by 36% for the three months ended March 31, 2022, compared with the same period of 2021, primarily due to increased energy costs, additional well services and maintenance costs.
- Transportation costs decreased by 16% for the three months ended March 31, 2022, compared with the same period of 2021, primarily due to no barrels being transported in Peru during the first quarter of 2022.
- Cost of purchases for the three months ended March 31, 2022, increased by $31.4 million compared with the same period of 2021, due to additional volumes being acquired from third parties to replace the dilution service and higher market price of those volumes. The sale of the volumes purchased represents an estimated income for the three months ended March 31, 2022 of $32.5 million.
- Dilution costs for the three months ended March 31, 2022, decreased by $6.7 million (or 96%), compared with the same period of 2021, mainly due to replacement of the dilution service by volumes purchased, lower dilution requirements resulting from the reduction in heavy oil production, optimization of dilution strategy of CPE-6 volumes moved to Puerto Bahia to sell as Llanos Blend.
- (Settlement) overlift was not significant for the first quarter of 2022. For the first quarter of 2021, there was an overlift settlement due to the payment of an overlift balance from 2020.
- Inventory valuation for the first quarter of 2022 decreased by $21.8 million, due to the build-up of inventory volumes in Colombia and Ecuador in the quarter compared with a drawdown of inventory in Peru during previous year.

Royalties

	Three months ended March 31	
($M)	**2022**	**2021**
Royalties Colombia	19,244	6,110
Royalties	**19,244**	**6,110**
$/boe using sales volumes	7.58	1.96

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three months ended March 31, 2022, royalties increased by $13.1 million, compared to the same period of 2021, primarily due to the increase in WTI oil benchmark price. Refer to the “Production Reconciled to Sales Volumes” section on page 5 for further details of royalties PAP paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended March 31	
($M)	**2022**	**2021**
Depletion, depreciation and amortization	38,784	32,636

For the three months ended March 31, 2022, depletion, depreciation and amortization expense (“**DD&A**”) increased by 19%, respectively, compared to the same period of 2021, mainly due to higher depletable base as a result of the reversal of impairment in fourth quarter 2021.

Impairment, Exploration Expenses and other

	Three months ended March 31	
($M)	**2022**	**2021**
Impairment	—	—
Exploration expenses	472	82
Recovery of asset retirement obligations	(4,429)	(5,738)
Impairment, exploration expenses and other	**(3,957)**	**(5,656)**

For the three months ended March 31, 2022 and 2021, the impairment was $Nil as no indicators were identified.

During the three months ended March 31, 2022, the Company recognized a recovery related to an asset retirement obligation of $4.4 million, compared to a recovery of $5.7 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.

Other Operating Costs

($M)	Three months ended March 31 2022	2021
General and administrative	14,656	13,202
Share-based compensation	5,088	1,317
Restructuring, severance and other costs	331	381

General and Administrative

For the three months ended March 31, 2022, G&A expenses increased by 11%, compared with the same period of 2021, mainly due to an increase in personnel costs and taxes during the three months ended March 31, 2022, compared to the same period of 2021.

Share-based Compensation

For the three months ended March 31, 2022, share-based compensation increased to $5.1 million from $1.3 million in the same period of 2021 mainly due to the increase in the Common Share price during 2022. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted stock units and grants of deferred stock units under the Company's security-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 ended March 31, 2022, restructuring, severance and other costs were comparable to those for the same period in 2021.

Non-Operating Costs

($M)	Three months ended March 31 2022	2021
Finance income	607	840
Finance expenses	(12,235)	(13,587)
Foreign exchange gain (loss)	3,642	(18,488)
Other loss, net	(6,019)	(9,601)

Finance Income

For the three months ended March 31, 2022, finance income decreased by $0.2 million compared to the same period in 2021, due to interest collected from VAT reimbursement in previous year.

Finance Expense

For the three months ended March 31, 2022, finance expenses decreased by $1.4 million, mainly due to a reduction in the interest rate from the new bonds, and lower interest on the 2025 Puerto Bahia Debt (as defined below) and lease liabilities.

Foreign Exchange Gain (Loss)

For the three months ended March 31, 2022, foreign exchange gain was $3.6 million, as a result of the COP's appreciation against the USD on the translation of the debt consolidated from Puerto Bahia and the translation of the Company's net working capital balances, compared with a loss of $18.5 million in the same period of 2021.

Other Loss, net

For the three months ended March 31, 2022, other loss was $6.0 million, primarily related to the recognition of contingencies in Peru, compared to other loss in the same period of 2021 of $9.6 million, related to the reassessment of contingencies from the late delivery of production from the Quifa block prior to 2014 (for further information refer to Note 27 of the 2021 Annual Financial Statements).

Loss on Risk Management Contracts

($M)	Three months ended March 31 2022	2021
Premiums paid on risk management contracts settled	(2,682)	(2,120)
Cash settlement on risk management contracts	—	(8,860)
Realized loss on risk management contracts	(2,682)	(10,980)
Unrealized gain (loss) on risk management contracts [1]	1,144	(8,838)
Total loss on risk management contracts	(1,538)	(19,818)

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 ended March 31, 2022, the realized loss on risk management contracts was $2.7 million resulting from cash paid for put options purchased, compared to a loss of $11.0 million, in the same period of 2021, primarily from the cash settlement on three-way collars, puts and put spreads contracts paid during the three months ended March 31, 2021.

The unrealized gain on risk management contracts for the three months ended March 31, 2022, was $1.1 million, compared to a gain of $8.8 million in the same period of 2021, primarily related to mark to market variances in interest rate swap contracts on the 2025 Puerto Bahia Debt and foreign exchange outstanding risk management contracts partially offset by the reclassification of amounts to realized loss from Brent crude oil instruments settled during the period.

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 a combination of instruments, capped and non-capped, to protect the revenue generation and cash position of the Company, while maximizing the upside. This diversification of instruments allows the Company to take a more dynamic approach to the management of its hedging portfolio and balancing cash costs. In 2022, the Company executed a risk management strategy using a variety of derivatives instruments, including mainly put options to protect against downward oil price movements.

Type of Instrument	Term	Benchmark	Notional Amount / Volume (bbl)	Avg. Strike Prices Put $/bbl	Carrying Amount ($M) Assets	Liabilities
Put	April to September 2022	Brent	2,765,000	70.0	3,648	—
Total as at March 31, 2022					**3,648**	**—**

Subsequent to March 31, 2022, the Company entered into new hedges to protect 2022 estimated production. The new transactions are as follows:

Type of Instrument	Term	Benchmark	Notional Amount / Volume (bbl)	Avg. Strike Prices Put $
Put	October to December 2022	Brent	1,410,000	70.0
		Total (bbl)	**1,410,000**	

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 March 31, 2022, the Company has outstanding 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	Liabilities
Zero-cost collars	April to June 2022	COP / USD	$ 60,000	3,750 / 4,402	956	—
Total as at March 31, 2022					**956**	**—**

Subsequent to March 31, 2022, the Company entered into new hedges to protect 2022 COP exposure . The new transactions are as follows:

Type of Instrument	Term	Benchmark	Notional Amount / Volume USD ($M)	Put/ Call; Par forward (COP$)
Zero-cost collar	July to December 2022	COP/USD	$ 120,000	3,750 / 4,420

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

The Company has a financial derivative 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 17 for further information. As at March 31, 2022, the Company had the following interest rate swap contract outstanding:

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount $M**	**Floating rate**	**Assets**	**Liabilities**
Swap	April 2022 to June 2025	LIBOR + 180	121,100	3.9%	—	3,923
Total as at March 31, 2022					**—**	**3,923**

Income Tax Recovery (Expense)

	Three months ended March 31	
($M)	**2022**	**2021**
Current income tax expense	(1,553)	(4,191)
Deferred income tax recovery (expense)	14,304	(9,089)
Total income tax recovery (expense)	**12,751**	**(13,280)**

Current income tax expense for the first quarter of 2022 was $1.6 million, compared with $4.2 million in the same quarter of 2021. The reduction is mainly due to changes in prior years’ tax assessments recognized during the first quarter of 2022, partially offset by withholding taxes on dividends from investments in associates, and current income tax expense during the first quarter of 2022.

Deferred income tax recovery for the first quarter of 2022 was $14.3 million, compared with $9.1 million expense for the same quarter of 2021, mainly due to a deferred tax asset recovery as a result of the COP revaluation during first quarter of 2022.

Net Income (Loss)

	Three months ended March 31	
($M)	**2022**	**2021**
Net income (loss) attributable to equity holders of the Company	102,228	(14,126)
Per share – basic ($)	1.08	(0.14)
Per share – diluted ($)	1.05	(0.14)

The Company reported net income of $102.2 million for the first quarter of 2022, which included operating income of $95.7 million, and deferred income tax recovery of $14.3 million partially offset by $6.0 million of other expenses and finance expense of $12.2 million. This compared to net loss of $14.1 million in the first quarter of 2021, which included a loss on risk management contracts of $19.8 million, foreign exchange loss of $18.5 million, and finance expense of $13.6 million, partially offset by $51.5 million of operating income.

Capital Expenditures and Acquisitions

	Three months ended March 31	
($M)	**2022**	**2021**
Development drilling	36,881	6,427
Development facilities	5,994	1,668
Colombia and Ecuador exploration	10,195	835
Other	6,967	260
Total Colombia, Ecuador and other capital expenditures	**60,037**	**9,190**
Guyana exploration	51,950	4,847
Guyana infrastructure	1,558	328
Total capital expenditures	**113,545**	**14,365**

Capital expenditures for the three months ended March 31, 2022, was $113.5 million, an increase of $99.2 million compared to the same period of 2021, mainly due to the following:

Colombia and Ecuador:

Development drilling. During the three months ended March 31, 2022, development drilling increased by $30.5 million compared to the same period of 2021, mainly due to a total of 14 development wells drilled in Quifa, Guatiquia and CPE-6 blocks in the first quarter of 2022 compared to 1 development well drilled during the first quarter of 2021.

Development facilities. During the three months ended March 31, 2022, development facilities were $6.0 million compared to $1.7 million during the same period of 2021, mainly related to additional flow handling and injector line facilities at the CPE-6 and Guatiquia blocks, road improvements at the CPE-6 block, and increased expenditures related to drilling equipment and environmental requirements at the Quifa block.

Exploration. For the three months ended March 31, 2022, exploration activities increased by $9.4 million, compared to the same period of 2021, mainly due to the finalization of Jandaya-1 well and the drilling of Tui-1 well in Ecuador during first quarter of 2022, compared to no exploration well drilled in the first quarter of 2021. Details relating to exploration activities in Colombia and Ecuador are as follows:

Colombia. The Company continues to focus on the Lower Magdalena Valley in Colombia, and in 2022, the Company plans to drill one exploration well in the VIM-1 block, one or two exploration wells in the VIM-22 block, and one exploration well in the La Creciente block. In addition, on January 18, 2022, the ANH signed with the Company a block exploration and production agreement for the VIM-46 block, which includes 58,806 hectares within the Magdalena Valley. The exploratory commitments include one exploration well during the first exploration phase. The Company is working on pre-seismic activities related to social and environmental impact studies in VIM-22, Llanos 119 and Llanos 99 blocks.

Ecuador. On December 7, 2021, the Company spud the Jandaya-1 well in the Perico block in Ecuador to test an exploration prospect in the northeastern portion of the block. The well reached total depth on December 31, 2021, and on January 19, 2022, testing was completed and a discovery was announced, with a total of 78 feet vertical depth of potential hydrocarbon bearing reservoir encountered in three formations. The Company is under long-term test, and will prepare the environmental impact assessment for obtaining a production environmental license. Additional appraisal activities will be conducted in the near future to confirm size and mid- to long-term production levels. On January 28, 2022, Frontera spud its second exploration well called Tui-1 in the southern portion of the Perico block. The Tui-1 exploration well was drilled to a total depth of 10,975 feet and was completed on March 22, 2022, in basal Tena. Additional prospects on the Perico block have been identified and are being matured for future drilling.

Other. For the three months ended March 31, 2022, the Company has capitalized other expenses for $7.0 million, mainly $5 million related to the purchase agreement signed with Repsol Colombia Oil & Gas Ltd. ("**RCOG**") to acquire its 50% of the CPE-6 block, as result of reaching 5MMbbl of production (For further information refer to the "Commitments and Contractual Obligations" section on page 20).

Guyana

Guyana exploration. For the three months ended March 31, 2022, the Company invested $51.9 million in the Corentyne block, mainly related to completion activities at the Kawa-1 well. Details relating to exploration activities in Guyana are as follows:

On August 22, 2021, the Company and majority-owned subsidiary and co-venture partner, CGX, commenced drilling operations on the Kawa-1 exploration well, located in the northern region of the Corentyne block. The Kawa-1 well was drilled to a total depth of 21,578 feet (6,577 metres). Drilling results confirmed the presence of an active hydrocarbon system at the Kawa-1 location. Successful wireline logging runs confirmed net pay of approximately 200 feet (61 metres) within Maastrichtian, Campanian, Santonian and Coniacian horizons. The joint venture did not get MDT data or sidewall core samples and has engaged an independent third-party to complete further detailed studies and laboratory analysis on drilling cuttings from the

Santonian, Campanian and Maastrichtian intervals and well-bore fluid samples to evaluate in situ hydrocarbons. Preliminary results from the Santonian interval indicate the presence of liquid hydrocarbons in the reservoir. Results from the Campanian and Maastrichtian intervals are pending.

Guyana infrastructure. During the three months ended March 31, 2022, Guyana infrastructure increased by $1.2 million compared to the same period in 2021, mainly related to costs associated with the Guyana Port Project (as defined below). For further information refer to the "Midstream Activities" section on page 14.

Acquisition of additional 35% W.I. in El Dificil Block

Subsequent to the quarter, on April 27, 2022, the ANH signed the amendment for the acquisition by Frontera of the 35% W.I. in El Dificil block. previously owned by PCR Investments S.A. (a wholly owned subsidiary of Petroquímica Comodoro Rivadavia S.A. ("PCR")), for a total aggregate cash consideration of approximately $13 million. The transaction will add approximately 500 boe/d of total production (consisting of approximately 2,600 mmcf/d of conventional natural gas and 45 bbl/d of natural gas liquids).

Selected Quarterly Information

		2022	2021				2020		
Operational and financial results		**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Heavy crude oil production	(bbl/d)	21,214	20,912	18,168	17,241	20,997	21,074	21,997	22,533
Light and medium crude oil production	(bbl/d)	17,248	16,300	17,160	17,142	18,294	19,502	19,550	18,107
Total crude oil production	(bbl/d)	38,462	37,212	35,328	34,383	39,291	40,576	41,547	40,640
Conventional natural gas production	(mcf/d)	9,530	4,663	5,033	5,164	5,227	6,356	7,895	9,399
Natural gas liquids	(boe/d)	966	575	211	393	391	254	270	308
Total production	(boe/d)	41,100	38,605	36,422	35,682	40,599	41,945	43,202	42,597
Sales volumes, net of purchases [1]	(boe/d)	28,211	39,001	26,672	34,151	34,555	44,551	39,966	35,963
Brent price	($/bbl)	97.90	79.66	73.23	69.08	61.32	45.26	43.34	33.39
Oil and gas sales, net of purchases [1]	($/boe)	90.42	75.12	67.13	64.54	58.18	42.20	40.18	24.96
Realized loss on risk management contracts	($/boe)	(1.06)	(1.87)	(2.68)	(8.00)	(3.53)	(2.00)	(1.70)	12.19
Royalties	($/boe)	(7.58)	(3.62)	(4.83)	(0.53)	(1.96)	(0.47)	(0.23)	—
Dilution costs [2]	($/boe)	(0.12)	(0.10)	(0.15)	(0.34)	(2.25)	(1.85)	(1.62)	(2.63)
Net sales realized price [2]	($/boe)	81.66	69.53	59.47	55.67	50.44	37.88	36.63	34.52
Production costs [2]	($/boe)	(13.48)	(12.71)	(11.44)	(11.72)	(10.06)	(12.95)	(8.55)	(8.68)
Transportation costs [2]	($/boe)	(9.74)	(9.02)	(10.24)	(11.15)	(11.30)	(11.36)	(10.24)	(11.56)
Operating netback	($/boe)	58.44	47.80	37.79	32.80	29.08	13.57	17.84	14.28
Revenue	($M)	254,627	301,969	182,673	224,685	184,734	177,109	152,760	81,701
Net income (loss)	($M)	102,228	629,376	38,531	(25,648)	(14,126)	48,636	(90,473)	(67,760)
Per share – basic ($)	($)	1.08	6.60	0.40	(0.26)	(0.14)	0.50	(0.93)	(0.70)
Per share – diluted ($)	($)	1.05	6.40	0.39	(0.26)	(0.14)	0.48	(0.93)	(0.70)
General and administrative	($M)	14,656	12,144	12,656	14,132	13,202	19,851	10,539	9,716
Operating EBITDA	($M)	132,770	148,323	72,646	83,072	69,158	35,639	52,113	37,608
Capital expenditures	($M)	113,545	135,458	103,220	61,214	14,365	24,871	2,905	15,651

1. The fourth quarter of 2020 and prior period figures are different compared with those previously reported as a result of the change in the treatment of purchased volumes and cost of purchases according with the current operating netback approach. Refer to the "Non-IFRS Measures" section on page 15 for further details.

2. The second quarter of 2021 and prior period figures are different compared with those previously reported as a result of a reclassification from production cost to transportation cost and dilution cost 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 cost.

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 the drilling activity and normalization of social conflicts at the peak of the pandemic in Colombia. In addition, since 2020 there has been a reduction in transportation costs due to the cessation of payments for unused facilities under the Bicentenario ancillary agreements and Caño Limon Coveñas ancillary agreements that were settled as part of the implementation of the Conciliation Agreement (for further information, refer to Note 28 of the Annual Consolidated Financial Statements and related notes for the years ended December 31, 2020 and 2019) and dilution cost decreased, since the second quarter of 2021, as a result of the replacement of dilution service by volumes purchased. Furthermore, production costs have increased due to increase in energy costs and well services.

Trends in the Company's net income (loss) are also impacted most significantly by the recognition and derecognition of deferred income taxes and impairment or reversal of impairment of oil and gas assets, debt extinguishment costs, reclassification of currency translation adjustment on the acquisition of control in Infrastructure Ventures Inc. ("**IVI**") and the disposal of the Company's 43.03% W.I. in Bicentenario, recognition of provisions related to the Conciliation Agreement (refer to note 27 of the 2021 Annual Consolidated Financial Statements), DD&A, 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.

Midstream Activities

The Company has investments in certain infrastructure and midstream assets, including storage and other facilities relating to the distribution and exportation of crude oil products in Colombia and the Company's investments in pipelines. Also, the Company has an indirect interest in an infrastructure project in Guyana consisting of a port concession which is currently under construction.

The midstream segment principally includes the following assets:

Project [1]	Description	Interest [2]	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	96.55% interest in Puerto Bahia	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/d	59.93% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [3]
Guyana Port Project	Multifunctional port facility	76.98% interest in CGX	Consolidation

1. The midstream 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 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.

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia, which consists of a hydrocarbon terminal and a dry 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 from 94.16% to 96.55%, through the conversion of certain debt held by the Company's subsidiaries, Frontera Bahia, IVI, and Frontera Energy Colombia AG into preferred shares with voting rights.

For the three months ended March 31, 2022, Puerto Bahia has generated $11.8 million of segment income from operations (first quarter of 2021: $10.0 million), primarily from services contracts in its liquid terminal, and RoRo (Roll-on/roll-off) in its general cargo terminal.

ODL Pipeline

The Company holds a 59.93% interest in PIL, which has a 35% equity investment in the Oleoducto de Los Llanos Orientales ("**ODL**") pipeline, which connects the Rubiales, Quifa, and Llanos-34 blocks to the Monterrey Station or Cusiana Station in the Casanare Department.

For the three months ended March 31, 2022, the Company recognized $9.1 million as its share of income from ODL, which was $0.7 million lower than the same period of 2021, primarily due to the impact of foreign exchange fluctuations. During the three months ended March 31, 2022, the Company recognized gross dividends of $40.5 million (first quarter of 2021: $41.6 million) and a return of capital of $3.9 million (first quarter of 2021: $4.2 million). As at March 31, 2022, the Company has accounts receivables of $29.8 million of dividends and return of capital contributions.

Guyana Port Project

CGX, Frontera's majority-owned subsidiary and joint venture partner, 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. For the three months ended March 31, 2022, CGX invested $1.6 million in the Guyana Port Project and the construction had no impact on the Company's income statement.

Midstream Segment Results

The Interim Financial Statements include the following amounts relating to the midstream segment:

	Three months ended March 31	
($M)	**2022**	**2021**
Revenue	19,824	16,845
Costs	(4,679)	(4,528)
General and administrative expenses	(1,671)	(1,476)
Depletion, depreciation and amortization	(1,476)	(793)
Restructuring, severance and other costs	(174)	—
Puerto Bahia income from operations	**11,824**	**10,048**
Share of Income from associates - ODL	9,094	9,786
Segment income	**20,918**	**19,834**

Non-IFRS Measures

This MD&A contains the following terms that do not have standardized definitions in IFRS: “operating EBITDA”, “oil and gas sales, net of purchases”, “net sales”, “operating netback”, “consolidated total indebtedness”, and “net debt”. These financial measures, together with measures prepared in accordance with IFRS, provide useful information to investors and shareholders, as management uses them to evaluate the operating performance of the Company.

The Company also reports “consolidated adjusted EBITDA” in accordance with the terms of the indenture (the “**Indenture**”) governing the Company’s 2028 Unsecured Notes (as defined below). Refer to the “Liquidity and Capital Resources” section on page 17.

The Company’s determination of these non-IFRS measures may differ from other reporting issuers and they are therefore unlikely to be comparable to similar measures presented by other companies. Furthermore, these non-IFRS measures should not be considered in isolation or as a substitute for measures of performance or cash flows as prepared in accordance with IFRS.

Operating EBITDA

EBITDA is a commonly used measure that adjusts net income (loss) as reported under IFRS to exclude the effects of income taxes, finance income and expenses, and DD&A. Operating EBITDA represents the operating results of the Company’s primary business, excluding the following items: restructuring, severance and other costs, certain non-cash items (such as impairments, foreign exchange, unrealized risk management contracts, and share-based compensation) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA, as they are not indicative of the underlying core operating performance of the Company. The following table provides a reconciliation of net income (loss) to operating EBITDA:

	Three months ended March 31	
($M)	**2022**	**2021**
Net income (loss)	102,228	(14,126)
Finance income	(607)	(840)
Finance expenses	12,235	13,587
Income tax (recovery) expense	(12,751)	13,280
Depletion, depreciation and amortization	38,784	32,636
Impairment, Exploration Expenses and other	(4,429)	(5,738)
Share-based compensation non cash portion	5,088	1,317
Restructuring, severance and other costs	331	381
Share of income from associates	(9,094)	(9,786)
Foreign exchange (gain) loss	(3,642)	18,488
Other loss, net	6,019	9,601
Unrealized (gain) loss on risk management contracts	(1,144)	8,838
Non-controlling interests	(248)	1,520
Operating EBITDA	**132,770**	**69,158**

Net Sales

Net sales are a non-IFRS subtotal 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 7.

Operating Netback and Oil and Gas Sales, Net of Purchases

Operating netback 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 6.

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, on a per boe basis is calculated using oil and gas sales less the cost of volumes purchased from third parties including its transportation and refining cost, divided by the total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2022	**2021**
Oil and gas sales ($M) [1]	264,991	184,960
(-) Cost of purchases ($M) [2]	(35,422)	(4,004)
Oil and gas sales, net of purchases ($M)	**229,569**	**180,956**
Sales volumes, net of purchases - (boe)	2,538,990	3,109,938
Oil and gas sales, net of purchases ($/boe)	90.42	58.18

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 14.
2. Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining costs.

Net sales realized price per boe 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) divided by the total sales volumes, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2022	**2021**
Net sales ($M)	207,345	156,883
Sales volumes, net of purchases - (boe)	2,538,990	3,109,938
Net sales realized price ($/boe)	81.66	50.44

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

	Three months ended March 31	
	2022	**2021**
Production costs ($M)	49,861	36,755
Production (boe)	3,699,000	3,653,910
Production costs ($/boe)	13.48	10.06

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

	Three months ended March 31	
	2022	**2021**
Transportation costs ($M)	32,153	38,473
Net production (boe)	3,300,120	3,405,330
Transportation costs ($/boe)	9.74	11.30

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:

	As at March 31
($M)	**2022**
Long-term debt [1]	$ 407,940
Total lease liabilities [2]	6,825
Risk management assets, net [3]	(4,604)
Consolidated Total Indebtedness	**410,161**
(-) Cash and Cash Equivalents [4]	(210,858)
(=) Net Debt	**$ 199,303**

1. Excludes $143.1 million of long-term debt attributable to the Unrestricted Subsidiaries.
2. Excludes $0.4 million of lease liabilities attributable to the Unrestricted Subsidiaries.
3. Excludes $3.9 million of risk management liabilities attributable to the Unrestricted Subsidiaries.
4. Includes Cash and cash equivalents attributable to the guarantors and borrower according to the Indenture.

4. LIQUIDITY AND CAPITAL RESOURCES

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

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

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

As of March 31, 2022, the Company had a total cash balance of $323.5 million (including $66.1 million in restricted cash), which is $2.7 million higher than December 31, 2021, and compared with a total cash position of $409.5 million, including $161.2 million of restricted cash, as of March 31, 2021. For the three months ended March 31, 2022, the Company generated $115.0 million in operating cash flows which were used to fund cash outflows of $105.6 million for capital expenditures and other investing activities. Financing outflows of $10.0 million for the three months ended March 31, 2022, included $6.1 million in common shares repurchased, $1.7 million of Petrosud Debt payments, $1.1 million of interest and other financing charges and $1.1 million in lease payments. As a result, the working capital deficit was reduced to $36.1 million compared with $78.9 million at year-end 2021.

Since 2020, the Company's consolidated 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 ($143.1 million as of March 31, 2022) classified as a current liability (for further information on the 2025 Puerto Bahia Debt, refer to page 19 hereof and Note 19 of the 2021 Annual Consolidated Financial Statements). The Company believes that working capital balances in conjunction with future cash flows from operations and available credit facilities are sufficient to support the Company's normal operating requirements, capital expenditures and financial commitments on an ongoing basis.

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As of March 31, 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 March 31, 2022, the Company had total restricted cash of $66.1 million, an increase of $2.8 million from December 31, 2021, primarily due to 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 22.

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, 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. Concurrent with the offering, the net proceeds of the 2028 Unsecured Notes were partially used to repurchase, at a premium and including accrued interest, the total obligation under the Company’s previously issued unsecured notes (the “2023 Unsecured Notes”), which were set to mature in 2023. The remaining proceeds were used for general corporate purposes.

The Company received tenders and consents from holders of $287.8 million (or 82.24%) of the aggregate principal amount of its 2023 Unsecured Notes, pursuant to its previously announced cash tender offer and consent solicitation made upon the terms and subject to the conditions set forth in the Offer to Purchase and Consent Solicitation Statement dated as of June 7, 2021, and the related Letter of Transmittal. The notes tendered prior to the early tender date were settled on June 21, 2021, and the notes tendered after the early tender date and prior to the expiration time were settled on July 7, 2021.

On July 7, 2021, the Company redeemed all of the remaining 2023 Unsecured Notes at a redemption price comprised of (i) 104.85% of the aggregate principal amount of the notes redemption, plus (ii) accrued and unpaid interest, if any, through the date of redemption, plus (iii) any other amounts accrued and unpaid thereon under the terms of the 2023 Unsecured Notes and the related indenture for the 2023 Unsecured Notes, including Additional Amounts (as defined such indenture), if any. The Company’s long-term borrowing of $350.0 million in respect of the 2023 Unsecured Notes was completely discharged on July 7, 2021.

The refinancing transaction successfully extended the maturity of and reduced the Company’s average cost of debt.

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 Energy Colombia AG and Frontera Energy Guyana Corp. 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) and Indebtedness in respect of the Puerto Bahia Funding up to $20.3 million. The 2028 Unsecured Notes also contain covenants that limit the Company’s ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at March 31, 2022, the Company is in compliance with all such covenants.

Pursuant to requirements under the Indenture, the Company reports as of March 31, 2022, consolidated total indebtedness of $410,161,000, and for the twelve months ended as of March 31, 2022, consolidated adjusted EBITDA of $432,054,000 and consolidated interest expense of $30,995,000.

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 under “Non-IFRS Measures” on page 15.

    b. Consolidated adjusted EBITDA is defined as the consolidated net income (loss) (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense and abandonment costs; after excluding the impact of the Unrestricted Subsidiaries.

2. Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most recent period ended of four consecutive fiscal quarters divided by the consolidated interest expense for such period as defined in the Indenture.

3. Consolidated net tangible assets is defined in the Indenture as the net amount of the Company’s total assets less intangible assets and current liabilities, after excluding the impact of the Unrestricted Subsidiaries.

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 (for further information refer to Note 4 of the 2021 Annual Consolidated Financial Statements).

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 (other than as provided for by the equity contribution agreement (“ECA”) described below), and has no impact on the Company’s financial covenants under the 2028 Unsecured Notes. As at March 31, 2022, the 2025 Puerto Bahia Debt outstanding amount is $143.1 million.

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 whenever Puerto Bahia had a deficiency in the reserve account supporting its bank loan. Amounts disbursed under the ECA are designated to the repayment of principal and interest from that loan. Pursuant to the terms of the ECA, Frontera has from time to time made loans to Puerto Bahia (“ECA Loans”) that are subordinated to the 2025 Puerto Bahia Debt and bear interest of 14%. The ECA loans give Frontera a direct claim against Puerto Bahia that is in priority to IVI’s equity interest in Puerto Bahia, and thus indirectly in priority to the claims of the remaining minority shareholders of IVI.

To date, the Company has advanced a total of $109.7 million under the ECA Loans, of which $68.3 million was capitalized into preferred shares and common shares of Puerto Bahia. As a result of the acquisition of control in IVI, all intercompany balances and transactions between the Company and IVI are eliminated on consolidation.

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 2021 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. PetroSud Debt bears interest at 3-month LIBOR plus 4.95% which is 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 reserve account for an amount of $1.1 million. As at March 31, 2022, the PetroSud Debt outstanding amount is $16.3 million. The PetroSud Debt is subject to covenants that require PetroSud to maintain a finance debt to EBITDA ratio that is less than or equal to 3.50:1.0 and a free cash flow debt service ratio that is greater than or equal to 1.20:1.0. In the event that these financial ratios are not met, Banco Davivienda S.A. is entitled to accelerate the PetroSud Debt. As at March 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 March 31, 2022, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $86.3 million (total credit lines of $106.9 million), without cash collateral.

Commitments and Contractual Obligations

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

As at March 31, 2022 ($M)	2022	2023	2024	2025	2026	2027 and Beyond	Total
Financial obligations							
2028 unsecured notes, principal and interest	31,500	31,500	31,500	31,500	31,500	447,250	604,750
Lease liabilities	4,534	3,159	82	52	—	—	7,827
2025 Puerto Bahía Debt and interest (1)	46,916	50,120	47,723	13,269	—	—	158,028
PetroSud Debt and interest	3,317	14,158	—	—	—	—	17,475
Total financial obligations	**86,267**	**98,937**	**79,305**	**44,821**	**31,500**	**447,250**	**788,080**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	52,717	70,289	70,289	35,144	—	—	228,439
ODL agreements	11,806	14,855	14,855	7,428	—	—	48,944
Other transportation and processing commitments	6,967	11,793	11,793	11,793	11,793	6,646	60,785
Exploration commitments							
Minimum work commitments (2)	80,545	90,488	17,265	24,351	—	—	212,649
Other commitments							
Operating purchases, leases and community obligations	35,671	18,735	12,050	17,200	8,709	15,732	108,097
Total Commitments	**187,706**	**206,160**	**126,252**	**95,916**	**20,502**	**22,378**	**658,914**

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 Exploration

As of March 31, 2022, the Company, through its 76.98% interest in CGX and directly through its 33,33% W.I. in the Corentyne and Demerara Blocks, has exploration work commitments under Petroleum Prospecting Licenses ("**PPL**") for certain Guyana blocks, as follows:

- In accordance with the Corentyne PPL, which is currently in phase two of the second renewal period, one exploration well must be drilled by November 26, 2022.
- On February 14, 2022, CGX and Frontera, the majority shareholder of CGX and joint venture partner of CGX in the petroleum prospecting license for the Demerara block, announced that as a result of the initial positive results at the Kawa-1 exploration well on the Corentyne block, the joint venture will focus on the significant exploration opportunities in the Corentyne block and will not engage in drilling activities on the Demerara block in 2022.

CGX (as operator) and Frontera, as joint venture partners have entered into agreements with suppliers for activities to complete requirements under the PPL for the Corentyne block. Also, CGX, has entered into agreements with suppliers for the Guyana Port Project. As at March 31, 2022, the aggregate minimum future obligation still outstanding under these agreements is $9.5 million, which is expected to be paid in 2022 (December 31, 2021: $32.1 million).

On April 22, 2021, the Company and CGX jointly announced that CGX, operator of the Corentyne block, had entered into an agreement with Maersk Drilling Holdings Singapore Pte. Ltd. ("**Maersk**") for the provision of a semi-submersible drilling unit owned by Maersk (the "**Maersk Discoverer**") and associated services to drill the joint venture's Kawa-1 well. In relation to that agreement, Frontera entered into a deed of guarantee with Maersk for certain obligations, up to a maximum of $25.0 million, and the option to drill a second well. On January 31, 2022, the Company and CGX announced that CGX had exercised its option with Maersk to drill a second well using the Maersk Discoverer.

Other Guarantees and Pledges

As part of the Company's acquisition of RCOG´s 50% W.I. 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 is achieved. As at March 31, 2022, the Company has paid or accrued a total of $10.9 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 ("**EMP**") 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's cash consideration was $1.8 million. In addition, during the first quarter of 2022, the Company made payments of $4.0 million related to outstanding commitments at COR-15.

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

On April 29, 2020, Ocensa and the Company entered into a pledge agreement pursuant to which the Company guaranteed payment to Ocensa through a pledge of the crude oil transported in the Ocensa Pipeline. The term of the pledge agreement has been amended and extended until April 30, 2022. During the term of the pledge agreement, Ocensa has agreed not to exercise its early termination and prepayment rights. The pledge agreement will automatically terminate if the Company subsequently meets certain credit conditions set forth in the ship-or-pay agreement.

In May 2022, a new ship-or-pay contract with Bicentenario and Cenit will take effect, and as a result, the pledged inventory crude oil will be 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 Cenit and Ocensa, which will guarantee the payment obligations of both contracts, for the period from May 1, 2022, to September 30, 2022, with Ocensa up to $30.0 million, and May 1, 2022, to October 31, 2022, with Cenit up to $6.0 million.

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 financial position, results of operations or cash flows.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at May 2, 2022:

	Number
Common shares	93,065,036
Deferred share units ("**DSUs**") (1)	785,897
Restricted share units ("**RSUs**") (2)	1,790,162

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. DSU settlements are determined by the sole discretion of the Compensation and Human Resources Committee of the Board (the "**CHRC**"), in Common Shares, cash or a combination thereof. 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. RSU settlements are determined by the sole discretion of the Compensation and Human Resources Committee of the Board, in Common Shares, cash or a combination thereof. Vesting of RSUs is 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 15, 2022, the TSX accepted the Company´s notice of intention to commence a new NCIB on March 17, 2022, upon the expiry of its previous NCIB (which expired on March 16, 2022). Pursuant to the new NCIB, the Company may purchase for cancellation up to 4,787,976 of its Common Shares during the 12-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. Purchases subject to the NCIB will be carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc., on behalf of Frontera in accordance with an automatic share purchase plan and applicable regulatory requirements. During the three months ended March 31, 2022, the Company purchased a total of 625,400 Common Shares under its current and previous NCIBs (237,200 under its current NCIB and 388,200 under its previous NCIB). As at May 2, 2022, the Company had repurchased for cancellation a total of 1,246,400 Common Shares under its new NCIB for approximately $14.2 million with an additional 3,541,576 Common Shares available for repurchase under the new NCIB. Under the prior NCIB that expired on March 16, 2022, the Company repurchased for cancellation during the twelve-month term and the three months ended March 31, 2022 a total of 4,243,600 and 388,200 Common Shares, for approximately $25.0 million and $3.5 million, respectively.

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

	Three months ended March 31
	2022
Number of common shares repurchased	625,400
Total amount of common shares repurchased ($M)	6,124
Weighted-average price per share ($)	9.79

6. RELATED-PARTY TRANSACTIONS

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

($M)		Accounts Receivable	Accounts Payable	Commitments	Purchases / Services
ODL	2022	29,779	284	48,944	5,363
	2021	—	112	56,716	9,072

7. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives including, but not limited to: production; liquidity/financial; health, safety and environmental; exploration, new business and reserves growth; information security; and political risk. The impact of any risk may adversely affect, among other things, the Company's business, reputation, financial condition, results of operations and cash flows, which may affect the market price of its securities.

The Company has an enterprise risk management program that plans, identifies, evaluates, prioritizes and monitors risk across the organization and supports decision-making. This program identifies critical strategic risk to its people, the environment, its assets, regulatory environment and reputation, and seeks to systematically mitigate these risks to an acceptable level. In addition, we continuously monitor our risk profile as well as industry best practices.

For a comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the AIF and the 2021 Annual Consolidated Financial Statements, copies of which are available on SEDAR at www.sedar.com.

In addition, the COVID-19 pandemic could have negative impacts on the Company's financial condition, results of operations, and cash flows. Despite successful vaccine rollouts in many jurisdictions, the risk of a resurgence or additional variant strains remains high and could result in continued fluctuations in the price of oil and conventional natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events could have 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.

Further, in February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the world economy. In addition, certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which may have 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 could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas could have a significant adverse impact on the world economy. 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, thus creating for operating companies an eventual temporary shortage of certain materials/equipment needed for the operation. Alternative sourcing is being planned and implemented. 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 17 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.

8. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Interim Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook -Accounting. A summary of significant accounting policies applied is included in Note 3a of the 2021 Annual Consolidated Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 2 of the Interim Financial Statements, including management’s evaluation of impact and implementation progress.

The preparation of the Interim Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss and the related disclosure of contingent assets and liabilities included in the Interim Financial Statements. The Company evaluates its estimates on an ongoing basis.

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

The effect of the COVID-19 pandemic on the world economy, and the associated volatility in oil prices, has impacted and continues to impact 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 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 Interim Financial Statements.

The results of the economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management’s judgments and estimates as described above for the quarter end; however, there could be further prospective material impacts in future periods. As such, actual results may differ from these estimates under different assumptions or conditions. A summary of the significant judgments and estimates made by management in the preparation of its financial information is provided in Note 3c of the 2021 Annual Consolidated Financial Statements.

9. INTERNAL CONTROL

In accordance with National Instrument 52-109 - Certification of Disclosure in Issuers’ Annual and Interim Filings (“**NI 52-109**”) of the Canadian Securities Administrators, the Company issues a “Certification of Interim Filings”. 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 the first quarter of 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.

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

The Company’s DC&P is designed to provide reasonable assurance that material information relating to the Company is made known to the Company’s certifying officers by others, particularly during the period in which the interim filings are being prepared, and that information required to be disclosed by 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.

On December 30, 2021, the Company closed its acquisition of PetroSud and PetroSud became a wholly-owned subsidiary of the Company. As permitted by and in accordance with NI 52-109, Management has limited the scope on the design of ICFR and DC&P of the Company to exclude the controls, policies and procedures of PetroSud. The scope limitation is in accordance with Section 3.3 of NI 52-109, which allows an issuer to limit its design of ICFR and DC&P of a company acquired not more than 365 days before the end of the financial period to which the certificate relates, and is primarily due to the time required for Management to assess the ICFR and DC&P relating to PetroSud in a manner consistent with the Company's operations. Integration activities have commenced and further integration will take place throughout the year 2022 as processes and systems align. Assets attributable to PetroSud as at March 31, 2022 represented approximately 1% of the Company's total assets, and $4.7 million revenues were consolidated for the quarter ended March 31, 2022 (for further information refer to Note 4 of the 2021 Annual Consolidated Financial Statements). 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.

10. FURTHER DISCLOSURES

Production Reporting

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

The following table includes the average net production:

		Net Production		
Producing blocks in Colombia		**Q1 2022**	**Q4 2021**	**Q1 2021**
Heavy crude oil	(bbl/d)	17,987	18,099	19,632
Light and medium crude oil	(bbl/d)	15,866	15,721	16,897
Conventional natural gas	(mcf/d)	9,530	4,663	5,227
Natural gas liquids	(boe/d)	962	575	391
Net production Colombia	**(boe/d)**	**36,487**	**35,213**	**37,837**
Producing blocks in Ecuador				
Light and medium crude oil	(bbl/d)	181	—	—
Net production Ecuador	**(bbl/d)**	**181**	**—**	**—**
Total net production	**(boe/d)**	**36,668**	**35,213**	**37,837**

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 7.

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	**mcf/d**	Thousand cubic feet per day
bbl/d	Barrels of oil per day	**Q**	Quarter
boe	Barrels of oil equivalent	**USD**	United States dollars
boe/d	Barrels of oil equivalent per day	**WTI**	West Texas Intermediate
COP	Colombian pesos	**W.I.**	Working interest
C$	Canadian dollars	**$**	U.S. dollars
MMbbl	Millions of oil barrels	**$M**	Thousand U.S. dollars
Mcf	Thousand cubic feet	**$MM**	Million U.S. dollars