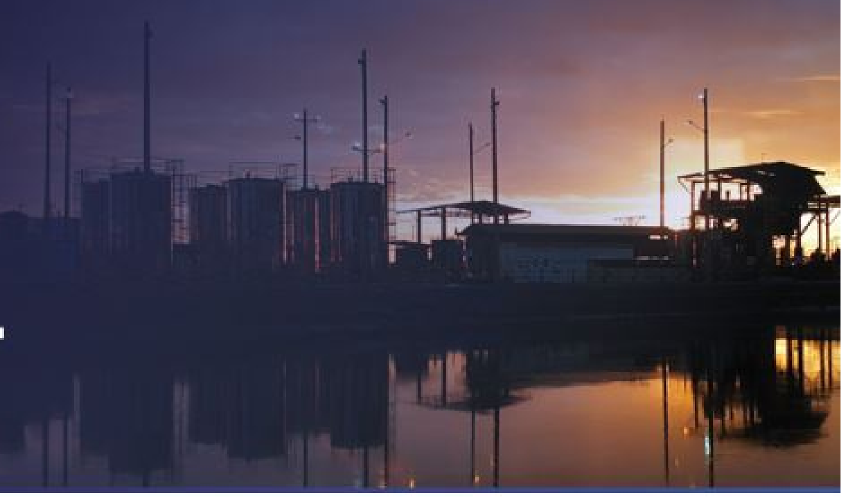
MANAGEMENT DISCUSSION & ANALYSIS

March 2, 2022
For the year ended December 31, 2021



*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 Consolidated Financial Statements and related notes for the years ended December 31, 2021 and 2020 ("**Annual Consolidated 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 22.*

*This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to activities, events or developments that the Company believes, expects or anticipates will or may occur in the future. Forward-looking information in this MD&A includes, without limitation, statements regarding estimates and/or assumptions in respect of the oil price environment, current and expected impacts of the COVID-19 pandemic, actions of the Organization of Petroleum Exporting Countries and Russia ("**OPEC+**"), 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," "likely," "possible," "probable," "scheduled," "positioned," "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.

1. MESSAGE TO THE SHAREHOLDERS

It is with great pride that I write this message to shareholders, almost one year to the day since I was named Chief Executive Officer of Frontera. 2021 was filled with many challenges and opportunities for the global economy and the oil and gas industry specifically. While the on-going impacts of COVID-19 continued to be felt around the world, renewed optimism, improved Brent oil prices and increased investment and activity gave fresh momentum to exploration and production companies around the world.

Implementing Frontera's "Building a Sustainable Future" ESG Strategy

Frontera achieved many strategic, operational, financial and shareholder value creation objectives in 2021, all underpinned by Frontera's company-wide commitment to the highest levels of health, safety, and environmental performance. In 2021, we implemented our "Building a Sustainable Future" ESG strategy, achieving 98% of our ESG goals for the year. The Company neutralized 41% of its emissions through carbon credits and preserved and restored 765 new hectares of key connectivity corridors in the Casanare and Meta departments in Colombia. The Company was awarded the Equipares Gold Seal for the Company's commitment to close gender gaps in the workplace and in the communities where it operates, recorded a total reportable incident rate of 1.70 and was recognized in 2021 for the first time as one of the World's Most Ethical Companies by Ethisphere.

Delivering On Our Objectives

In March 2021, we outlined our strategic, operational and financial objectives for 2021. I'm pleased to report that we substantially delivered on all of our objectives.

Strategy

One of the most important objectives we successfully delivered in 2021 was the extension in June of our bond maturity to 2028 and in parallel, decreasing the coupon from 9.7% to 7.875%, significantly improving the covenant and guarantors packages and increasing the size of the bond from $350 to $400 million assuring greater financial stability for the next six years. In November, we completed a settlement agreement with Cenit and Bicentenario, which represented the final step in resolving all the disputes between the parties related to the Bicentenario Pipeline and the Caño Limón – Coveñas Pipeline. The agreement eliminates more than $1 billion in contingent liabilities, opens up different strategic options for the company and is an incredibly important milestone for Frontera, its shareholders and partners in Colombia.

In December we acquired 100% of the shares of Petroleos Sud Americanos S.A. ("**PetroSud**") with operations in Colombia in El Dificil (65% W.I.), Entrerrios and Rio Meta blocks (100% W.I. in each block) and we also signed an agreement to acquire the remaining 35% interest in El Dificil block from PCR Investments S.A., a wholly-owned subsidiary of Petroquimica Comodoro Rivadavia S.A. ("**PCR**") (the deal is subject to Agencia Nacional de Hidrocarburos´ ("**ANH**") approval and is expected to close later in 2022). These transactions support the Company's strategy to increase gas production, lower carbon emissions and includes strategically located, high quality gas facilities. The addition of the El Dificil, Entrerrios and Rio Meta blocks add further diversity, flexibility and optionality to an already diverse asset base which includes our interests in Guyana, Ecuador, and Colombia.

We also delivered solid reserves results in 2021, replacing 157% of net 1P reserves and 105% of net 2P reserves and extending our net 1P reserves life index to 8.7 years and our net 2P reserves life index to 13.3 years. We also increased net 2P natural gas and associated natural gas liquids reserves by 105% to 19.1 MMboe, further diversifying Frontera's future production mix. The net present value (10% discount) on December 31, 2021 of the Company's 2P reserves increased by 61% to $3.036 billion before tax due in part to higher Brent prices year over year and greater operational and development cost stability.

Shareholder Value Creation

In 2021, Frontera repurchased approximately 3,855,400 common shares or 7.4% of the public float for cancellation for approximately $21.5 million under our current NCIB as of December 31, 2021. Since 2018, the Company has reduced its production costs by 8.4% and reduced its transportation costs by 18.3%. Since 2018, Frontera has also returned $206.7 million to shareholders through dividends and buybacks.

Operations

In 2021, we executed $314.3 million in total capital spending as we increased activity across our portfolio throughout the year. In Colombia, we drilled 42 producer wells, 3 injector wells, and completed 148 workovers and well services. This activity allowed us to deliver average production of 37,818 boe/d (consisting of 19,326 bbl/d of heavy crude oil, 17,218 bbl/d of light and medium crude oil, 5,022 Mcf/d of conventional natural gas and 393 boe/d of natural gas liquids), in-line with 2021 Guidance (as defined below). Significantly, we began early production of approximately 2,400 boe/d (gross) at the La Belleza block discovery on VIM-1 (50% W.I., non-operator). Frontera's daily production on March 1, 2022 was approximately 42,000 boe/d (consisting of approximately 21,500 bbl/d of heavy oil, 17,850 bbl/d of light and medium crude oil, 9,400 mcf/d of conventional natural gas and 1,000 boel/d of natural gas liquids) and the Company's year-to-date average to March 1, 2022 was approximately 40,500 boe/d (consisting of approximately 21,000 bbl/d of heavy oil, 16,850 bbl/d of light and medium crude oil, 9,400 mcf/d of conventional natural gas and 1,000 boe/d of natural gas liquids).

Additionally, the ANH agreed to extend the Hamaca Field by 115,869 net acres to the north of the current CPE-6 block boundary area, providing the Company with additional near-field exploration and growth opportunities adjacent to our existing and expanding CPE-6 facilities. We discovered hydrocarbons at the Jandaya-1 exploration well in Ecuador, we were officially awarded Block VIM-46 by the ANH in the 2021 Colombia Bid Round and we confirmed 200 feet of net pay within multiple horizons at Kawa-1 exploration well in Guyana.

Financials

Frontera delivered strong financial results in 2021. We generated approximately $373.2 million of EBITDA, up 117% compared to 2020 and within our tightened and increased 2021 Guidance range. We reduced transportation costs by 10% and our G&A by 5%. We released approximately $105.6 million of restricted cash and we increased our uncollateralized credit lines to $82.8 million. Our operating netback increased by 134% and our net sales realized price increased by 54.6%. Importantly, we exited 2021 with a strong total cash position of $320.8 million including restricted cash of $63.3 million.

Looking Ahead

I am incredibly excited about Frontera's future. We're developing a strong and integrated ESG platform that guides operations and improves the Company's performance and reputation. We have a proven and diverse asset base which generates value focused production and cash flow from across our portfolio. We continue to decrease breakeven costs over time, concentrating capital expenditures on the sweet spots of our portfolio to deliver value over volume. We have world class exploration opportunities in Guyana, and exciting low risk exploration potential in Ecuador and Colombia, which offers attractive upside for the Company.

Thank you to Frontera's Board, Management team and all the Frontera employees and contractors for their commitment and dedication to safely, responsibly and productively delivering on our 2021 objectives. I look forward to building on our success in 2022 and beyond.

"Orlando Cabrales Segovia"
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q4 2021	Q3 2021	Q4 2020	Year ended December 31 2021	Year ended December 31 2020
Operational Results						
Heavy crude oil production	(bbl/d)	20,912	18,168	21,074	19,326	24,384
Light and medium crude oil production	(bbl/d)	16,300	17,160	19,502	17,218	21,519
Total crude oil production (1)	(bbl/d)	37,212	35,328	40,576	36,544	45,903
Conventional natural gas production (1)	(mcf/d)	4,663	5,033	6,356	5,022	8,807
Natural gas liquids (1)	(boe/d)	575	211	254	393	352
Total production (2)	(boe/d) (3)	38,605	36,422	41,945	37,818	47,800
Oil and gas sales, net of purchases (4)	($/boe)	75.12	67.13	42.20	66.54	38.20
Realized (loss) gain on risk management contracts	($/boe)	(1.87)	(2.68)	(2.00)	(4.01)	2.42
Royalties	($/boe)	(3.62)	(4.83)	(0.47)	(2.66)	(0.57)
Dilution costs	($/boe)	(0.10)	(0.15)	(1.85)	(0.72)	(1.78)
Net sales realized price (5)	($/boe)	69.53	59.47	37.88	59.15	38.27
Production costs (6)	($/boe)	(12.71)	(11.44)	(12.95)	(11.46)	(10.73)
Transportation costs (7)	($/boe)	(9.02)	(10.24)	(11.36)	(10.43)	(11.60)
Operating netback (4)	($/boe)	47.80	37.79	13.57	37.26	15.94
Financial Results						
Oil & gas sales, net of purchases	($M)	269,525	164,731	172,980	815,793	645,348
Realized (loss) gain on risk management contracts	($M)	(6,692)	(6,570)	(8,205)	(49,119)	40,924
Royalties	($M)	(12,974)	(11,848)	(1,925)	(32,572)	(9,686)
Dilution costs	($M)	(368)	(366)	(7,584)	(8,773)	(30,088)
Net sales (4)	($M)	249,491	145,947	155,266	725,329	646,498
Net income (loss) (8)	($M)	629,376	38,531	48,636	628,133	(497,406)
Per share – basic	($)	6.60	0.40	0.50	6.50	(5.13)
Per share – diluted	($)	6.40	0.39	0.48	6.29	(5.13)
General and administrative	($M)	12,144	12,656	19,851	52,134	55,121
Operating EBITDA (4)	($M)	148,323	72,646	35,639	373,199	172,342
Cash provided by operating activities	($M)	113,482	79,114	42,055	327,380	226,781
Capital expenditures (9)	($M)	135,458	103,220	24,871	314,257	108,103
Cash and cash equivalents – unrestricted	($M)	257,504	318,791	232,288	257,504	232,288
Restricted cash short and long-term	($M)	63,321	100,692	168,934	63,321	168,934
Total cash	($M)	320,825	419,483	401,222	320,825	401,222
Total debt and lease liabilities	($M)	560,135	563,173	538,244	560,135	538,244
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) (4)(10)	($M)	416,883	401,148	362,001	416,883	362,001
Net debt (excluding Unrestricted Subsidiaries) (4)(10)	($M)	207,578	130,680	146,978	207,578	146,978

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* ("**NI 51-101**").
2. Represents W.I. production before royalties and total volumes produced from service contracts. Refer to the "Further Disclosures" section on page 36.
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 36.
4. Non-IFRS financial measures. Refer to the "Non-IFRS Measures" section on page 22. 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 from development and producing ("**D&P**") assets. Volumes purchased from third parties are excluded.
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. Capital expenditures includes costs, net of income and cost from exploration and evaluation ("**E&E**") assets.
10. "**Unrestricted Subsidiaries**" include CGX Energy Inc.("**CGX**"), Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. ("**PIL**"), Frontera BIC Holding Ltd., Frontera Bahía Holding Ltd., including its subsidiary Sociedad Portuaria Puerto Bahía S.A. ("**Puerto Bahia**").

Performance Highlights

Full Year 2021

- Production averaged 37,818 boe/d in 2021 (consisting of 19,326 bbl/d of heavy crude oil, 17,218 bbl/d of light and medium crude oil, 5,022 Mcf/d of conventional natural gas and 393 boe/d of natural gas liquids), compared with 47,800 boe/d in 2020 (consisting of 24,384 bbl/d of heavy crude oil, 21,519 bbl/d of light and medium crude oil, 8,807 Mcf/d of conventional natural gas and 352 boe/d of natural gas liquids).
- Cash provided by operating activities was $327.4 million in 2021, compared with $226.8 million in 2020, contributing to a total cash position as at December 31, 2021, of $320.8 million, compared with $401.2 million as at December 31, 2020. Total cash includes $63.3 million of restricted cash, compared with $168.9 million as at December 31, 2020.
- Net income was $628.1 million ($6.29/share) in 2021, compared with a net loss of $497.4 million ($5.13/share) in 2020.
- Capital expenditures were $314.3 million in 2021, compared with $108.1 million in 2020.
- Operating EBITDA was $373.2 million in 2021, compared with $172.3 million in 2020.
- Operating netback was $37.26/boe in 2021, compared with $15.94/boe in 2020.

Fourth Quarter 2021

- Production averaged 38,605 boe/d in the fourth quarter of 2021 (consisting of 20,912 bbl/d of heavy crude oil, 16,300 bbl/d of light and medium crude oil, 4,663 Mcf/d of conventional natural gas and 575 boe/d of natural gas liquids), compared with 36,422 boe/d in the prior quarter (consisting of 18,168 bbl/d of heavy crude oil, 17,160 bbl/d of light and medium crude oil, 5,033 Mcf/d of conventional natural gas and 211 boe/d of natural gas liquids), and 41,945 boe/d in the fourth quarter of 2020 (consisting of 21,074 bbl/d of heavy crude oil, 19,502 bbl/d of light and medium crude oil, 6,356 Mcf/d of conventional natural gas and 254 boe/d of natural gas liquids).
- Cash provided by operating activities was $113.5 million in the fourth quarter of 2021, compared with $79.1 million in the prior quarter and $42.1 million in the fourth quarter of 2020. The Company reported a total cash position of $320.8 million, including $63.3 million of restricted cash, as at December 31, 2021, compared with a total cash position of $401.2 million, including $168.9 million of restricted cash, as at December 31, 2020.
- Net income was $629.4 million ($6.60/share) in the fourth quarter of 2021, compared with net income of $38.5 million ($0.40/share) in the prior quarter and net income of $48.6 million ($0.50/share) in the fourth quarter of 2020.
- Capital expenditures were $135.5 million in the fourth quarter of 2021, compared with $103.2 million in the prior quarter and $24.9 million in the fourth quarter of 2020.
- Operating EBITDA was $148.3 million in the fourth quarter of 2021, compared with $72.6 million in the prior quarter and $35.6 million in the fourth quarter of 2020. The increase in operating EBITDA quarter-over-quarter was primarily a result of two more cargoes sold during the fourth quarter of 2021.
- Operating netback was $47.80/boe in the fourth quarter of 2021, compared with $37.79/boe in the prior quarter and $13.57/boe in the fourth quarter of 2020.

Oil and Gas Reserves

- Frontera delivered 105% 2P reserves replacement, added 13.1 MMboe of 2P net reserves and extended its reserve life index to 13.3 years at year end 2021.
- Frontera's 2021 year-end net 2P reserves additions were primarily driven by technical revisions of 11.2 MMboe at the La Belleza and Guatiquia blocks, 6.0 MMboe from the acquisition of the El Dificil (65% W.I.), Entrerrios and Rio Meta blocks, and 1.4 MMboe from Jandaya discovery in the Perico block in Ecuador. These additions were primarily offset by 12.5 MMboe of 2021 production, 5.5 MMboe of technical revision in several fields and an increase in high price clause participation ("**PAP**") royalties related to the Quifa block, impacting the net reserves in the block. Proved net reserves of 109.3 MMboe now represent 65% of the total 2P reserves compared with 61% of the total 2P reserves in 2020. The Company's booked reserves for the year ended December 31, 2021, are located in Colombia and Ecuador.

3. GUIDANCE

The Company's 2021 financial and operational results were in-line with all revised 2021 annual guidance metrics (the "**2021 Guidance**"), with the exception of capital expenditures which were over the high end. The Company had previously narrowed its 2021 Guidance range on July 16, 2021, for capital expenditures to $245-$295 million, and raised its 2021 Guidance range on November 2, 2021, for Operating EBITDA by 6%, primarily due to the increase in the Brent oil price since the second quarter of 2021.

In 2021, production averaged 37,818 boe/d, which was close to the midpoint of 2021 Guidance of 37,500 to 39,500 boe/d, as a result of a production increase in the CPE-6 block and the commencement of production in the VIM-1 block in the fourth quarter of 2021. This increase was partially offset by lower production from the Quifa block due to reductions in water disposal volumes throughout the year.

Production costs of $11.46/boe were slightly below the high end of 2021 Guidance of $10.50/boe to $11.50/boe, mainly as a result of the reduction in volumes produced. Transportation costs of $10.43/boe were within 2021 Guidance of $10.00/boe to $11.00/boe.

Operating EBITDA in 2021 totaled $373.2 million, within 2021 Guidance of $360-$380 million, mainly as a result of an increase in revenue by higher Brent oil price and reductions in transportation costs.

Capital expenditures of $314.3 million in 2021 were above the 2021 Guidance, mainly as a result of an increase in exploration costs in Guyana and exploration activities in Colombia, as well also increase of operational activity in Colombia.

		2021	
		Actual	Guidance
Average production	(boe/d)	37,818	37,500 to 39,500
Production costs	($/boe)	11.46	10.50 to 11.50
Transportation costs	($/boe)	10.43	10.00 to 11.00
Operating EBITDA (1)	($MM)	373.2	360 to 380
Development capital	($MM)	143.9	110 to 130
Exploration capital	($MM)	162.4	115 to 130
Infrastructure and other capital	($MM)	8.0	20 to 35
Capital expenditures (2)	($MM)	314.3	245 to 295

1. The 2021 Guidance Operating EBITDA assumed $72/bbl Brent and foreign exchange rate of 3,750 COP to 1 USD.
2. Capital Expenditures 2021 Guidance excluded decommissioning cost of $6 million.

2022 Guidance

The Company expects its total 2022 capital program to be approximately $340–$395 million on a consolidated basis. This includes $130–$140 million in development capital to maintain the Company's production volumes delivering 40,000–43,000 boe/d, $40–$50 million on development facilities, primarily in support of enhanced production at VIM-1, CPE-6, and Quifa blocks, and $50–$60 million on exploration activities in Colombia and Ecuador. The Company anticipates spending between $110-$130 million on Guyana exploration activities, primarily to drill the Wei-1 well offshore. The remaining capital budget of $5–$10 million will be directed towards infrastructure investments in the Guyana Port Project (as defined below).

Production costs are expected to average $11.0–$12.0/boe, higher than previous years, mainly due to the increased inflationary pressure, and higher energy and maintenance costs.

Transportation costs are expected to average $10.0–$11.0/boe, in-line with full year 2021 results. Transportation costs include new take or pay contracts with Bicentenario-Caño Limon, which are not expected to materially impact the Company's transportation costs. The Company anticipates generating operating EBITDA of approximately $375-$425 million at $70/bbl Brent prices, $475-$525 million at $80/bbl Brent prices, and $575-$625 million at $90/bbl Brent prices. The Company does not anticipate paying any material cash income taxes in Colombia in 2022, highlighting the benefit of the Company's strong tax pool position.

		FY 2022 Guidance
Average production	boe/d	40,000 - 43,000
Production costs	$/boe	11.00 - 12.00
Transportation costs	$/boe	10.00 - 11.00
Operating EBITDA at $70/bbl (1)	$MM	375 - 425
Development Drilling	$MM	130 - 140
Development Facilities	$MM	40 - 50
Colombia and Ecuador Exploration	$MM	50 - 60
Other	$MM	5
Total Colombia and Ecuador Upstream Capital Expenditures	$MM	225 - 255
Guyana Exploration	$MM	110 - 130
Guyana Port Project	$MM	5 - 10
Capital Expenditures (2)	$MM	340 - 395

1. Current Guidance Operating EBITDA calculated at $70/bbl Brent and foreign exchange rate of 3,750 COP to 1 USD.
2. Capital Expenditures excludes decommissioning cost of $10 million.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2021, the Company received an independent certified reserves evaluation report ("**Reserves Report**") from DeGolyer and MacNaughton for all of its assets, with total net 2P reserves of 167.0 MMboe compared with 166.4 MMboe certified reserves in 2020. The 2P reserves additions of 13.1 MMboe were primarily driven by technical revisions of 11.2 MMboe mainly at the La Belleza and Guatiquia block fields, 6.0 MMboe from the acquisition of the El Dificil (65% W.I.), Entrerrios and Rio Meta blocks, and 1.4 MMboe from Jandaya discovery in the Perico block in Ecuador. These additions were primarily offset by 12.5 MMboe of 2021 production, 5.5 MMboe of technical revision in several fields and an increase in PAP royalties related to the Quifa block, impacting the net reserves in the block. Proved net reserves of 109.3 MMboe now represent 65% of the total 2P reserves compared with 61% of the total 2P reserves in 2020.

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

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

Reserves at December 31, 2021 (MMboe (1) (5))								
Country	Field	Proved (P1)		Probable (P2)		Proved + Probable (2P)		Hydrocarbon Type
		Gross	Net	Gross	Net	Gross	Net	
Colombia	Quifa SW block	48.3	42.2	6.0	5.2	54.3	47.3	Heavy Oil
	Other heavy oil blocks (2)	35.1	33.8	22.1	21.7	57.1	55.4	Heavy Oil
	Light/medium oil blocks (3)	25.8	24.5	20.1	19.3	46.0	43.8	Light and Medium Oil
	Natural gas blocks (4)	6.5	6.5	5.8	5.8	12.4	12.4	Natural Gas
	Natural gas blocks (4)	1.6	1.6	5.1	5.1	6.7	6.7	Natural gas liquids
	Sub total	**117.4**	**108.6**	**59.1**	**57.0**	**176.5**	**165.6**	Oil and Natural gas
Ecuador	Perico Block	0.9	0.8	0.8	0.7	1.8	1.4	Light and Medium Oil
	Total at Dec. 31, 2021	**118.3**	**109.3**	**60.0**	**57.7**	**178.2**	**167.0**	Oil and Natural gas
	Total at Dec. 31, 2020	108.0	102.2	66.0	64.2	174.0	166.4	
	Difference	10.3	7.2	(6.1)	(6.5)	4.2	0.6	
	2021 Production	13.7	12.5	**Total reserves incorporated**		17.9	13.1	

1. See the "Further Disclosures - Boe Conversion" section on page 36.
2. Includes Cajua and Jaspe fields in the Quifa block, and Sabanero and CPE-6 blocks.
3. Includes the Cubiro, Cravoviejo, Canaguaro, Guatiquia, Casimena, Corcel, Neiva, Cachicamo and other producing blocks.
4. Includes the VIM 1, El Dificil and La Creciente blocks.
5. In the table above, "Gross" refers to working interest before royalties, and "Net" refers to working interest after royalties. Numbers in the table may not add due to rounding differences.

5. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia. Peru was reported until the first quarter of 2020, when operations there were suspended. Refer to the "Further Disclosures" section on page 36 for details of the Company's net production.

			Production			
Producing blocks in Colombia		**Q4 2021**	**Q3 2021**	**Q4 2020**	**FY 2021**	**FY 2020**
Heavy crude oil	(bbl/d)	20,912	18,168	21,074	19,326	24,384
Light and medium crude oil	(bbl/d)	16,300	17,160	19,502	17,218	20,180
Conventional natural gas	(mcf/d)	4,663	5,033	6,356	5,022	8,807
Natural gas liquids	(boe/d)	575	211	254	393	352
Total production Colombia	**(boe/d)**	**38,605**	**36,422**	**41,945**	**37,818**	**46,461**
Producing blocks in Peru [(1)]						
Light and medium crude oil	(bbl/d)	—	—	—	—	1,339
Total production Peru	**(bbl/d)**	**—**	**—**	**—**	**—**	**1,339**
Total production	**(boe/d)**	**38,605**	**36,422**	**41,945**	**37,818**	**47,800**

Colombia

Production in Colombia for the three months ended December 31, 2021, increased by 6% compared to the prior quarter. Higher production was a result of the growth in production in the heavy crude oil blocks, mainly in the Quifa and CPE-6 blocks as a result of development drilling and water disposal improvements during the fourth quarter. This was partially offset by a reduction in the conventional natural gas and light and medium crude oil blocks due to natural decline.

Compared to the fourth quarter of 2020 and year ended December 31, 2020, production in the fourth quarter of 2021 and year ended December 31, 2021, decreased by 8% and 19%, respectively, as a result of natural decline in the conventional natural gas and light and medium crude oil blocks, and reductions of water disposal volumes at Quifa at the end of the first quarter 2021, partially offset by an increase in CPE-6 block production due to development drilling, water disposal improvements and the construction of facilities for fluids treatment.

Peru

The Company reported no production in Peru for the three months and year ended December 31, 2021, compared to no production in the fourth quarter of 2020 and 1,339 bbl/d in the year ended December 31, 2020. The service contract for Block 192 had no operations since February 2020, and expired on February 5, 2021, at which time it was returned to Perupetro S.A. ("**Perupetro**"). The Company continues selling oil inventory and completing remediation work in the block. The Company's Block Z1 in Peru is not in production since December 19, 2019.

Production Reconciled to Sales Volumes

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

					Year ended December 31	
		Q4 2021	Q3 2021	Q4 2020	2021	2020
Production	(boe/d)	**38,605**	**36,422**	**41,945**	**37,818**	**47,800**
Royalties in-kind Colombia	(boe/d)	(3,392)	(3,435)	(2,818)	(3,127)	(3,299)
Royalties in-kind Peru [(1)]	(boe/d)	—	—	—	—	(221)
Net production	(boe/d)	**35,213**	**32,987**	**39,127**	**34,691**	**44,280**
Oil inventory draw (build)	(boe/d)	6,697	(4,938)	6,443	845	3,625
(Settlement) overlift	(boe/d)	(1)	(3)	609	(155)	150
Volumes purchased	(boe/d)	3,861	3,500	130	2,868	189
Other inventory movements [(2)]	(boe/d)	(2,201)	(1,867)	(1,732)	(1,943)	(1,935)
Sales volumes	(boe/d)	**43,569**	**29,679**	**44,577**	**36,306**	**46,309**
Sale of volumes purchased	(boe/d)	(4,568)	(3,007)	(26)	(2,718)	(156)
Sales volumes, net of purchases	(boe/d)	**39,001**	**26,672**	**44,551**	**33,588**	**46,153**
Oil sales volumes	(bbl/d)	38,177	25,773	43,490	32,707	44,650
Conventional natural gas sales volumes	(mcf/d)	4,697	5,124	6,048	5,022	8,567
Total oil and conventional natural gas sales volumes, net of purchases	(boe/d)	**39,001**	**26,672**	**44,551**	**33,588**	**46,153**
Inventory balance						
Colombia	(bbl)	326,861	943,121	119,792	326,861	119,792
Peru [(3)]	(bbl)	480,200	480,200	995,585	480,200	995,585
Inventory ending balance	**(bbl)**	**807,061**	**1,423,321**	**1,115,377**	**807,061**	**1,115,377**

1. The Company reported the share of production retained by the government of Peru as royalties paid in-kind.
2. Mainly corresponds to operational consumption and quality volumetric compensation.
3. The Company sold 500,000 bbl in Peru during the first half of 2021.

Sales volumes, net of purchases for the three months ended December 31, 2021, increased by 46% compared with the prior quarter, reducing the inventory volumes in Colombia in the quarter. In comparison to the fourth quarter of 2020 and the year ended December 31, 2020, sales volumes, net of purchases decreased by 12% and 27%, respectively, primarily due to lower volumes sales in Colombia as a consequence of production decreases.

Colombia Royalties PAP

The Company makes PAP payments to Ecopetrol S.A. and the ANH on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo and Arrendajo 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).

		Q4 2021	Q3 2021	Q4 2020	FY 2021	FY 2020
PAP in cash	(bbl/d)	684	257	70	345	225
PAP in kind	(bbl/d)	1,272	1,143	—	716	65
PAP	**(bbl/d)**	1,956	1,400	**70**	1,061	290
% Production		**5.1 %**	**3.8 %**	**0.2 %**	**2.8 %**	**0.6 %**

For the three months and year ended December 31, 2021, PAP increased compared with the same periods of 2020, primarily due to higher WTI oil benchmark price.

Realized and Reference Prices

		Q4 2021	Q3 2021	Q4 2020	Year ended December 31 2021	2020
Reference price						
Brent	($/bbl)	79.66	73.23	45.26	70.95	43.21
Average realized prices						
Realized oil price, net of purchases	($/bbl)	74.94	68.70	42.54	67.34	38.72
Realized conventional natural gas price	($/mcf)	4.12	3.88	4.16	3.98	3.87
Net sales realized price						
Oil and gas sales, net of purchases	($/boe)	75.12	67.13	42.20	66.54	38.20
Realized (loss) gain on risk management contracts	($/boe)	(1.87)	(2.68)	(2.00)	(4.01)	2.42
Royalties	($/boe)	(3.62)	(4.83)	(0.47)	(2.66)	(0.57)
Dilution costs [(1)]	($/boe)	(0.10)	(0.15)	(1.85)	(0.72)	(1.78)
Net sales realized price	**($/boe)**	**69.53**	**59.47**	**37.88**	**59.15**	**38.27**

1. 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 since the third quarter reflects decreased usage of the dilution service as the Company adopts this more cost efficient approach.

The average Brent benchmark oil price during the three months and year ended December 31, 2021, increased by 76% and 64%, respectively, compared to the same periods of 2020. In comparison to the third quarter of 2021, the average Brent benchmark oil price increased by 9%. The increase in crude oil prices in 2021 has been the result of the agreement between the members of OPEC+ to reduce production in an attempt to balance the markets. For the fourth quarter of 2021, demand continued to perform better than expected, boosted by China, India and United States consumption. Crude oil prices were also supported by natural gas prices, especially in Europe, as higher prices led to a fuel source switching from gas to oil, increasing demand by approximately 500 Kpd. The new strain of COVID-19, Omicron, impacted crude oil prices at year end to the downside, nonetheless, crude oil prices recovered promptly as the fears regarding the new strain effects on the demand side have been dissipated. Additionally, some key oil consumer countries led by the United States, released the strategic petroleum reserves to cope with crude oil price increases. OPEC+ stuck to its plan to increase 400 Kpd in its production ceiling, as planned.

For the three months and year ended December 31, 2021, the Company's net sales realized price was $69.53/boe and $59.15/boe, respectively, an increase of 84% and 55% compared to the same periods of 2020. The increase is mainly the result of higher Brent benchmark price, narrower differentials during year ended 2021, and reduction in dilution costs due to replacement of the dilution service by volumes purchased, partially offset by higher cash royalties, realized losses on risk management contracts during the year ended 2021, and lower differentials for the fourth quarter of 2021. In comparison to the third quarter of 2021, the net sales realized price increased by 17%, or $10.06/boe, primarily driven by the increase in the benchmark oil price, and higher volumes sold reducing the per boe effect from losses on risk management contracts and royalties during the fourth quarter of 2021.

Operating Netback

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

	Q4 2021		Q3 2021		Q4 2020	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1) (2)	249,491	69.53	145,947	59.47	155,266	37.88
Production costs (3)	(45,137)	(12.71)	(38,317)	(11.44)	(49,976)	(12.95)
Transportation costs (4)	(29,225)	(9.02)	(31,072)	(10.24)	(40,882)	(11.36)
Operating Netback (5)	**175,129**	**47.80**	**76,558**	**37.79**	**64,408**	**13.57**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases D&P (2) (6)		39,001		26,672		44,551
Production (7)		38,605		36,422		41,945
Net production (8)		35,213		32,987		39,127

1. Per boe is calculated using produced sales volumes from D&P assets. Refer to "Realized and Reference Prices" on page 10.
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 according with the current operating netback approach. Refer to the "Non-IFRS Measures" section on page 22 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 20 for further details.
4. Per boe is calculated using net production after royalties.
5. Refer to the "Non-IFRS Measures" section on page 22 for details and a description of the operating netback calculation.
6. Sales volumes, net of purchases D&P exclude sales of third-party volumes and volumes from E&E assets as the related sales and costs are capitalized.
7. Refer to the "Production" section on page 8.
8. Refer to the "Further Disclosures" section on page 36.

Operating netback for the fourth quarter of 2021 was $47.80/boe, compared to $13.57/boe in the same quarter of 2020. The increase was primarily due to higher net sales realized price and lower transportation costs. The transportation cost per boe decreased $2.34/boe, primarily due to the recognition of prepaid services from the Bicentenario ancillary agreements and Caño Limon Coveñas ancillary agreements (the "**Ancillary Agreements**") paid in 2020, as part of the implementation of the Conciliation Agreement (refer to the "Conciliation Agreement" section on page 29 for further details), termination of the take or pay contracts for the Monterrey - El Porvenir pipeline, and the offloading facilities in Monterrey, Santiago and Oleoducto de Los Llanos Orientales ("**ODL**"). The production costs per barrel were in line with the previous year.

In comparison to the third quarter of 2021, operating netback for the fourth quarter of 2021 increased from $37.79/boe to $47.80/boe, primarily due to higher net sales realized price and reduction in transportation costs mainly due to the recognition of prepaid services from the Ancillary Agreements paid in 2020, as part of the implementation of the Conciliation Agreement (refer to the "Conciliation Agreement" section on page 29 for further details), partially offset by the increase in production costs mainly due to additional well services, maintenance activities, and the increase in power supply and communities costs.

The following table provides a summary of the Company's netbacks for the year ended December 31, 2021:

	Year ended December 31			
	2021		2020	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1) (2)	725,329	59.15	646,498	38.27
Production costs (3)	(158,252)	(11.46)	(187,741)	(10.73)
Transportation costs (4)	(132,029)	(10.43)	(188,039)	(11.60)
Operating Netback (5)	**435,048**	**37.26**	**270,718**	**15.94**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases D&P (2) (6)		33,588		46,153
Production (7)		37,818		47,800
Net production (8)		34,691		44,280

References 1 through 8 are consistent with those included in the quarterly Operating Netback above.

Operating netback for the year ended December 31, 2021, increased to $37.26/boe from $15.94/boe in 2020. The increase was primarily due to higher net sales realized price and reduction of transportation cost due to (i) the recognition of prepaid services of the Ancillary Agreements paid in 2020 as part of the implementation of the Conciliation Agreement (refer to the "Conciliation Agreement" section on page 29 for further details), (ii) accounting eliminations from the consolidation of Puerto Bahia since the third quarter of 2020, (iii) termination of the take or pay contracts for the Monterrey - El Porvenir pipeline and offloading facilities in Monterrey, Santiago and ODL, and, (iv) the recovery of certain claims from previous years in favour of the Company, partially offset by higher production cost per barrel mainly due to lower production.

Sales

($M)	Three months ended December 31		Year ended December 31	
	2021	2020	2021	2020
Oil and gas sales, net of purchases [1]	269,525	172,980	815,793	645,348
Realized (loss) gain on risk management contracts	(6,692)	(8,205)	(49,119)	40,924
Royalties	(12,974)	(1,925)	(32,572)	(9,686)
Dilution cost	(368)	(7,584)	(8,773)	(30,088)
Net sales	**249,491**	**155,266**	**725,329**	**646,498**
$/boe using sales volumes from D&P assets	69.53	37.88	59.15	38.27

1. “Oil and gas sales, net of purchases” is a non-IFRS measure and includes crude oil and conventional natural gas sales, net of the cost of the third-party volumes purchased. For further detail refer to the “Non-IFRS Measures” section on page 22.

Oil and gas sales, net of purchases, increased by $96.5 million and $170.4 million for the three months and year ended December 31, 2021, respectively, compared to the same periods of 2020, mainly due to higher Brent benchmark oil prices (refer to the “Realized and Reference Prices” section on page 10 for further detail on changes in prices).

Net sales for the three months and year ended December 31, 2021, increased by $94.2 million and $78.8 million, respectively, compared with the same periods of 2020. The following table describes the various factors that impacted net sales:

($M)	Three months ended December 31	Year ended December 31
	2020-2021	2020-2021
Net sales for the period ended December 31, 2020	155,266	646,498
Increased due to 78% higher oil and gas price (YTD 74% higher)	134,899	478,683
Decrease due to lower volumes sold of 13,324 boe/d or 33% (YTD 14,925 boe/d or 32% lower)	(38,354)	(308,238)
Change to realized loss on risk management contracts	1,513	(90,043)
Decrease in dilution costs	7,216	21,315
Increase in royalties	(11,049)	(22,886)
Net sales for the period ended December 31, 2021	**249,491**	**725,329**

Oil and Gas Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2021	2020	2021	2020
Production costs	45,137	49,976	158,252	187,741
Transportation costs	29,225	40,882	132,029	188,039
Cost of purchases [1]	37,176	67	82,725	2,712
Dilution costs	368	7,584	8,773	30,088
Post-termination obligation	322	—	4,980	—
(Settlement) Overlift	(3)	2,700	(2,641)	2,970
Inventory valuation	16,281	4,180	12,499	37,776
Total oil and gas operating costs	**128,506**	**105,389**	**396,617**	**449,326**

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 22.

For the three months ended December 31, 2021, total oil and gas operating costs increased by 22% compared to the same period of 2020. For the year ended December 31, 2021, total oil and gas operating costs decreased 12% compared to the same period of 2020. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs for the three months and year ended December 31, 2021 were 10% and 16% lower, respectively, than the same periods of 2020, primarily due to lower production and to the closure of higher cost of Peru operations since February 5, 2021. In addition, as the Company took significant steps to optimize its production costs by renegotiating key contractor rates in response to the decline in oil prices during 2020, these actions resulted in reduced power supply costs, internal transport, chemical treatment, and rental expenses.

- Transportation costs decreased by 29% for the three months ended December 31, 2021, compared with the same period of 2020, primarily due to the recognition of prepaid services from the Ancillary Agreements paid in 2020, as part of the Conciliation Agreement (refer to the "Conciliation Agreement" section on page 29 for further details). For the year ended December 31, 2021, transportation costs decreased by 30% compared with the same period of 2020, primarily due to less barrels transported in Colombia as a result of lower production, the cessation of payments for unused facilities under the Ancillary Agreements since March 2020, the termination of the take or pay contracts for the Monterrey - El Porvenir pipeline, and offloading facilities at Monterrey, Santiago and ODL, and accounting eliminations from the consolidation of Puerto Bahia since August 6, 2020.
- Cost of purchases for the three months and year ended December 31, 2021, increased by $37.1 million and $80.0 million, respectively, compared with the same periods of 2020, due to additional volumes 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 and year ended December 31, 2021 of $32.6 million and $68.4 million respectively.
- Dilution costs for the three months and year ended December 31, 2021, decreased by $7.2 million (or 95%) and $21.3 million (or 71%), respectively, compared with the same periods of 2020, 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, and accounting eliminations from the consolidation of Puerto Bahia since August 6, 2020.
- Post-termination obligation for the three months and year ended December 31, 2021 was $0.3 million and $5.0 million, respectively, and includes environmental commitments, abandonment costs, and operational cost related to Block 192 in Peru, Guaduas, and Orito blocks in Colombia.
- Settlement / overlift was not significant for the fourth quarter of 2021. For the year ended December 31, 2021, settlement / overlift decreased due to the settlement of an overlift balance during the first half of 2021.
- Inventory valuation for the fourth quarter of 2021 increased by $12.1 million due to the drawdown of inventory volumes in Colombia in the quarter. For the year ended December 31, 2021, inventory valuation decreased by $25.3 million mainly due to the drawdown of inventory in Colombia and Peru during 2020.

Costs Under Terminated Pipeline Contracts

For the three months and year ended December 31, 2021, the Company recorded recovery costs of $4.4 million as a result of the implementation of the Conciliation Agreement. For the same periods of 2020, the Company recorded $99.1 million and $118.7 million of costs mainly due to the recognition of a non-cash provision related to the Conciliation Agreement and the Ancillary Agreements. For further information refer to the "Conciliation Agreement" section on page 29.

Royalties

	Three months ended December 31		Year ended December 31	
($M)	**2021**	**2020**	**2021**	**2020**
Royalties Colombia	12,974	1,925	32,572	9,643
Royalties Peru	—	—	—	43
Royalties	**12,974**	**1,925**	**32,572**	**9,686**
$/boe using sales volumes from D&P assets	3.62	0.47	2.66	0.57

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three months and year ended December 31, 2021, royalties increased by $11.0 million and $22.9 million, respectively, compared to the same periods of 2020 primarily due to the increase in WTI oil benchmark price. Refer to the "Production Reconciled to Sales Volumes" section on page 9 for further details of royalties paid in-cash and in-kind.

Depletion, Depreciation and Amortization

($M)	Three months ended December 31 2021	Three months ended December 31 2020	Year ended December 31 2021	Year ended December 31 2020
Depletion, depreciation and amortization	20,121	51,637	126,692	258,867

For the three months and year ended December 31, 2021, depletion, depreciation and amortization expense ("**DD&A**") decreased by 61% and 51%, respectively, compared to the same periods of 2020, mainly due to lower depletable base as a result of a reduction in abandonment cost and future capital expenditures, and the production decrease during the three months and year ended December 31, 2021, compared to the same periods of 2020.

Impairment (Reversal) Expense, Exploration Expenses and other

($M)	Three months ended December 31 2021	Three months ended December 31 2020	Year ended December 31 2021	Year ended December 31 2020
Impairment (reversal) expense of:				
Properties plant and equipment	(586,659)	(43,129)	(586,659)	34,735
Intangible assets	—	—	—	54,881
Exploration and evaluation assets	26,009	32,019	26,009	49,858
Other	1,462	1,603	1,462	2,491
Total impairment (reversal) expense	**(559,188)**	**(9,507)**	**(559,188)**	**141,965**
Exploration expenses	1,266	2,410	1,513	3,876
Recovery of asset retirement obligations	(3,332)	(4,923)	(6,335)	(4,452)
Impairment (reversal) expense, exploration expenses and other	**(561,254)**	**(12,020)**	**(564,010)**	**141,389**

For the three months and year ended December 31, 2021, the Company recognized a net impairment reversal of $586.7 million. The Company's certified 2021 year-end reserves report resulted in an increase in the total proved and probable reserves and a higher net present value than the carrying amount of its oil and gas properties. As a result, the Company performed an impairment reversal test and concluded that the recoverable amount for the Central Cash Generating Units ("CGU") exceeded its carrying amount resulting in a net reversal of previous impairment charges of $586.7 million.

The recoverable amount of each CGU was determined based on the Company's updated projections of future cash flows generated from proved and probable reserves. For further information refer to Note 8 of the 2021 Annual Consolidated Financial Statements.

For the three months and year ended December 31, 2021, was recorded an impairment of $26.0 million, related to exploration and evaluation assets. $20.1 million was recorded in Guyana, due to the Company is prioritizing its work plan in Corentyne block, and $5.9 million was recorded in in Colombia due to non-commercial exploratory test results, and plans to abandon further work on certain exploration projects from Colombia. In addition, $1.5 million of other impairment charges were recognized mainly related to slow moving or obsolete inventories.

For the three months and year ended December 31, 2021, the Company recorded exploration expenses of $1.3 million and $1.5 million, respectively, related to geological and geophysical costs including payroll, expenses incurred prior to obtaining the legal rights to explore an area, and payments made to fulfill the remaining balance of minimum exploration work commitment for certain blocks.

During the three months and year ended December 31, 2021, the Company recognized a recovery related to the asset retirement obligation of $3.3 million and $6.3 million, respectively, compared to a recovery of $4.9 and $4.5 million in the same periods of 2020. When a decrease in the asset retirement obligations exceeds the carrying amount of the related asset, or there is an increase in the asset retirement obligations related to fully impaired or relinquished assets, the change is recognized as a recovery or expense of asset retirement obligations.

For the three months and year ended December 31, 2020, the Company recognized an impairment reversal in property, plant and equipment of $43.1 million and impairment charges of $34.7 million, respectively, primarily as a result of lower forecasted oil prices, which reduced the expected future cash flows of its CGUs during the first quarter 2020, and due to the intangible assets in Colombia being fully impaired. Subsequently, the property, plant and equipment impairment was partially reversed during the fourth quarter of 2020, as a consequence of improvements in the forecasted oil prices. Additionally, for the three months and year ended December 31, 2020, the Company recognized impairment charges of $32.0 million and $49.9 million, respectively, of E&E assets mainly due to technical results and changes in development plans for certain exploration projects from Colombia. Impairment charges of $1.6 million and $2.5 million, respectively, were recognized mainly related to slow moving or obsolete inventories.

Other Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2021	2020	2021	2020
General and administrative	12,144	19,851	52,134	55,121
Share-based compensation	2,973	1,181	8,394	3,960
Restructuring, severance and other costs	1,746	7,340	4,616	21,097

General and Administrative

For the three months and year ended December 31, 2021, G&A expenses decreased 39% and 5%, respectively, compared with the same periods of 2020, mainly due to costs efficiencies, reduced discretionary spending and lower personnel costs from organizational restructuring activities, in addition to lower legal fees during the three months ended December 31, 2021, compared to the same period of 2020.

Share-based Compensation

For the three months and year ended December 31, 2021, share-based compensation increased to $3.0 million and $8.4 million, respectively, from $1.2 million and $4.0 million in the same periods of 2020 mainly due to the increase in the Frontera share price during 2021. Share-based compensation reflects cash and non-cash charges relating to the vesting of restricted share units and grants of deferred share units under the Company's incentive plan, which are subject to variability from movements in its underlying share price, and the consolidation of stock option expenses from the Company's majority-held subsidiary, CGX.

Restructuring, Severance and Other Costs

For the three months and year ended December 31, 2021, restructuring, severance and other costs decreased by $5.6 million and $16.5 million, respectively, compared with the same periods of 2020, primarily due to higher severance charges, as part of the Company's efforts to streamline operations in response to the lower oil price environment.

Non-Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2021	2020	2021	2020
Finance income	30	6,665	5,362	19,529
Finance expenses	(11,768)	(18,778)	(51,822)	(58,421)
Foreign exchange (loss) gain	(11,128)	27,840	(35,510)	(7,742)
Other income (loss), net	14,788	(3,043)	1,435	(47,328)
Reclassification of currency translation adjustments	(103,599)	—	(103,599)	(23,956)

Finance Income

For the three months ended December 31, 2021, finance income decreased by $6.6 million compared to the same period in 2020, as a result of the accretion income on dividends from Bicentenario, during 2020, which did not occur during 2021 due to the Conciliation Agreement (refer to the "Conciliation Agreement" section on page 29 for further details). In addition, for the year ended December 31, 2021, finance income decreased by $14.2 million compared to the same period in 2020, mainly due to the accounting elimination of the interest income from the long-term receivable to Infrastructure Venture Inc. ("IVI") after its consolidation.

Finance Expense

For the three months ended December 31, 2021, finance expenses decreased by $7.0 million compared to the same period in 2020, mainly as a result of the reduction in the interest rate from the new bonds, lower interest on lease liabilities, and accretion related to the dividends receivable from Bicentenario in 2020. For the year ended December 31, 2021, finance expense decreased by $6.6 million compared to the same period of 2020, mainly due to a reduction in the interest rate from the new bonds, lower interest on lease liabilities, partially offset by an increase in interest expense from the debt consolidated from Puerto Bahia.

Foreign Exchange (Loss) Gain

For the three months and year ended December 31, 2021, foreign exchange loss was $11.1 million and $35.5 million, respectively, as a result of the COP's depreciation 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 gain of $27.8 million and a loss of $7.7 million in the same periods of 2020. For the fourth quarter of 2020, was a gain due to the impact of the COP's revaluation against the USD on the translation of the debt consolidated from Puerto Bahia.

Other Income (Loss), net

For the three months ended December 31, 2021, other income was $14.8 million, mainly due to a gain of $12.8 million from a bargain purchase resulting from the acquisition of PetroSud, and non-recurrent income of $1.7 million from the settlement of a claim with a supplier, compared to other loss in the same period of 2020 of $3.0 million, relating to the recognition of legal claim provisions. For the year ended December 31, 2021, other income was $1.4 million, primarily due to $12.8 million from the bargain purchase gain resulting from the acquisition of PetroSud, partially offset by $7.8 million mainly related to the provision of the allegedly late delivery of production from the Quifa block prior to 2014 (for further information refer to Note 27 of the Annual Consolidated Financial Statements), and $3.6 million loss related to the disposal of M&P's interest during the fourth quarter of 2021, compared with other losses of $47.3 million in the same period of 2020, primarily driven by a non-cash loss of $42.8 million resulting from the acquisition of IVI.

Reclassification of currency translation adjustments

For three months and year ended December 31, 2021, the Company recognized a non-cash loss of $103.6 million related to the Cumulative Foreign Currency Translation Adjustments ("**CTA**") from other equity reserves as a result of the disposal of the Company's 43.03% interest in Bicentenario as part of the finalization of the Conciliation Agreement (refer to the "Conciliation Agreement" section on page 29 for further details). For the year ended December 31, 2020, the Company recognized a non-cash loss of $24.0 million on the reclassification of CTA from other equity reserves. The CTA loss primarily relates to historical functional currency COP to USD presentation currency translation differences on Bicentenario and IVI, as an investment in associates.

(Loss) Gain on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2021**	**2020**	**2021**	**2020**
Realized (loss) gain on risk management contracts [(1)]	(6,692)	(8,205)	(49,119)	40,924
Unrealized gain (loss) on risk management contracts [(2)]	4,530	741	7,213	(6,481)
Total (loss) gain on risk management contracts	(2,162)	(7,464)	(41,906)	34,443

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

For the three months and year ended December 31, 2021, the realized loss on risk management contracts was $6.7 million and $49.1 million, respectively, compared to a loss of $8.2 million, and a gain of $40.9 million in the same periods of 2020, primarily from the cash settlement on three-way collars, puts and put spreads contracts paid during the three months and year ended December 31, 2021, at an average price of $79.66/bbl.

The unrealized gain on risk management contracts for the three months and year ended December 31, 2021, was $4.5 million and $7.2 million, respectively, compared to a gain of $0.7 million and a loss of $6.5 million in the same periods of the previous year, primarily related to the reclassification of amounts to realized gain or loss from 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 2021, the Company executed a risk management strategy using a variety of derivatives instruments, including puts and zero-cost collars primarily to protect against downward oil price movements.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads ($/bbl)**	**Assets**	**Liabilities**
Zero-cost collars	January 2022	Brent	55,000	60.0/102.0	1	—
Put	January to April 2022	Brent	970,000	60.0	273	—
Put	January to March 2022	Brent	550,000	60.0	—	279
Total as at December 31, 2021					**274**	**279**

Subsequent to December 31, 2021, the Company entered into 2,640,000 bbls new puts hedges to protect 2022 estimated production up to September 2022 at $70/bbl strike, and upgraded 565,000 existing hedges as of December 31, 2021 from $60/bbl strike to $70/bbl strike.

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. The Company monitors its exposure to such foreign currency risks. As at December 31, 2021, 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	Carrying Amount Liabilities
Zero-cost collars	January to June 2022	COP / USD	$ 120,000	3,725 / 4,273	—	276
Total as at December 31, 2021					**—**	**276**

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 (as defined below). Refer to the “Liquidity and Capital Resources” section on page 25 for further information. As at December 31, 2021, the Company had the following interest rate swap contract outstanding:

Type of Instrument	Term	Benchmark	Notional Amount $M	Avg. Strike Prices Floating rate	Carrying Amount ($M) Assets	Carrying Amount ($M) Liabilities
Swap	January 2022 to June 2025	LIBOR + 180	121,100	3.9%	—	6,258
Total as at December 31, 2021					**—**	**6,258**

Income Tax Recovery (Expense)

	Three months ended December 31		Year ended December 31	
($M)	**2021**	**2020**	**2021**	**2020**
Current income tax (expense) recovery	(2,178)	9,541	(26,568)	480
Deferred income tax recovery (expense)	38,296	134,215	25,529	(33,764)
Total income tax recovery (expense)	**36,118**	**143,756**	**(1,039)**	**(33,284)**

Current income tax expense for the fourth quarter of 2021 was $2.2 million, compared with a recovery of $9.5 million in the same quarter of 2020. The change is mainly due to the calculation of the tax for the year 2021 in Colombia, compared with a reversal from a provision due to a voluntary settlement of tax uncertainties in Colombia in 2020.

Deferred income tax recovery for the fourth quarter of 2021 was $38.3 million compared with $134.2 million for the same quarter of 2020, mainly due to the recognition of $45.3 million of deferred tax asset, partially offset by $7.0 million from the deferred tax asset utilization in 2021.

For the year ended December 31, 2021, current income tax expense was $26.6 million, compared with a recovery of $0.5 million in the same period of 2020. The increase is mainly due to a provision of $18.3 million, related to changes in prior year tax assessments.

Deferred income tax recovery for the year ended December 31, 2021 was $25.5 million compared with a expense of $33.8 million in the same period of 2020. The 2021 recovery is related to $45.3 million of additional deferred tax asset offset by $19.8 million of deferred tax asset utilization. The 2020 expenses is related to the derecognition of deferred tax assets.

Net Income (Loss)

	Three months ended December 31		Year ended December 31	
($M)	**2021**	**2020**	**2021**	**2020**
Net income (loss) attributable to equity holders of the Company	629,376	48,636	628,133	(497,406)
Per share – basic ($)	6.60	0.50	6.50	(5.13)
Per share – diluted ($)	6.40	0.48	6.29	(5.13)

The Company reported net income of $629.4 million for the fourth quarter of 2021, which included operating income of $697.1 million (including a non-cash reversal of impairment of $561.3 million) and $36.1 million income tax recovery, partially offset by $103.6 million related to CTA as a result of the disposal of the Company’s 43.03% interest in Bicentenario. This compared to net income of $48.6 million in the fourth quarter of 2020, which included total income tax recovery of $143.8 million, partially offset by an operating loss of $100.9 million, including a $99.1 million non-cash provision related to the Conciliation Agreement. (Refer to the “Conciliation Agreement” section on page 29 for further details).

For the year ended December 31, 2021, the Company reported net income of $628.1 million, which included $854.2 million of operating income (including a non-cash reversal of impairment of $564.0 million), partially offset by $103.6 million related to the CTA as a result of the disposal of the Company's 43.03% interest in Bicentenario, $41.9 million loss on risk management contracts, $51.8 million finance costs expenses, and $29.1 million debt extinguishment costs. This compared to a net loss of $497.4 million in the same period of 2020, which included a $408.7 million loss from operations (including a $141.4 million non-cash impairment charge and $118.7 million provision from the Conciliation Agreement), $66.8 million non-cash loss resulting from the acquisition of IVI, and the net derecognition of deferred tax assets of $33.8 million.

Capital Expenditures and Acquisitions

	Three months ended December 31		Year ended December 31	
($M)	**2021**	**2020**	**2021**	**2020**
Development capital	60,242	15,930	143,888	74,081
Exploration activities [1]	72,400	8,566	162,370	32,344
Infrastructure and other capital	2,816	375	7,999	1,678
Total capital expenditures [2]	**135,458**	**24,871**	**314,257**	**108,103**

1. Includes expenditures, net of income from E&E assets.
2. Acquisition of PetroSud is not considered in this total

Capital expenditures for the three months and year ended December 31, 2021, were $135.5 million and $314.3 million, respectively. Compared to the same periods of 2020, capital expenditures increased by $110.6 million and $206.2 million, respectively, mainly due to the following:

- **Development capital.** During the three months and year ended December 31, 2021, development capital increased by $44.3 million and $69.8 million, respectively, compared to the same periods of 2020, mainly due to a total of 14 and 42 development wells drilled in Quifa, Guatiquia, CPE-6, and La Creciente blocks. During the fourth quarter of 2020, the Company restarted development activities which had been suspended due to the impact of the COVID-19 pandemic, drilling a well on the CPE-6 block, and for the year ended December 31, 2020, drilled 22 development wells in Quifa, CPE-6, and Sabanero blocks.
- **Exploration activities.** For the three months and year ended December 31, 2021, exploration activities increased by $63.8 million and $130.0 million, respectively, compared to the same periods of 2020, mainly due to two exploration wells drilled in Colombia (2020: one), and two exploration wells spud in Guyana and Ecuador completed during first quarter of 2022, detailed as follows:

Colombia

On the VIM-1 block in Colombia, during the second quarter of 2021, the Basilea-1 well was drilled to a total depth of 10,864 feet encountered gas shows through the shallower Porquero Formation but failed to reach its primary target due to mechanical problems. The drill rig was moved to the Planadas-1 location, approximately seven kilometers west of the La Belleza discovery. The Planadas-1 exploration well was drilled to a measured depth of ~13,700 feet and yielded no hydrocarbons. The operator of the block used the sole risk provision to proceed with a sidetracking operation to investigate a nearby updip target.

The Company's priority continues to be the Lower Magdalena Valley, 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 the VIM-46 block E&P agreement. The block includes 58,806 hectares within the prolific Magdalena Valley on the trend of several producing fields. The exploratory commitments include one exploration well during the first exploration phase. The Company is planning to start the environmental permitting process to drill the exploration well.

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 subsequent to the year end 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 now preparing the required permits to move forward with a long term test for at least six months or a longer period of time if approved by authorities. In parallel, the co-venturers 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 exploration well in the southern portion of the Perico block. The Tui-1 exploration well is expected to be drilled to a total depth of 10,972 feet and is targeting the same Hollin formation as Jandaya-1. Additional prospects on the Perico block have been identified and are being matured for future drilling.

Guyana

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 confirm 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.

On January 31, 2022, the Company and CGX announced that CGX had exercised its option with Maersk to drill a second commitment well using the Maersk Discoverer. The second commitment well, called Wei-1, will target Campanian and Santonian aged stacked channels in the western fan complex in the northern section of the Corentyne block, and is anticipated to spud in the second half of 2022. Kawa-1 well results have improved the joint venture's understanding of the operational and geological complexities of the basin and will help reduce the technical risks of the Wei-1 exploration well.

For the three months and year ended December 31, 2021, the Company invested $60.4 million and $116.1 million, respectively, in the Corentyne block.

- **Infrastructure and other capital.** During the three months and year ended December 31, 2021, infrastructure and other capital increased by $2.4 million and $6.3 million, mainly related to the Guyana Port Project. For further information refer to the "Midstream Activities" section on page 21.

Acquisition of PetroSud and the El Dificil Block

On December 30, 2021, the Company acquired 100% of the issued and outstanding shares of PetroSud, a Swiss company with operations in Colombia in the El Dificil (a 65% W.I.), Entrerrios and Rio Meta blocks (a 100% W.I. on each block). Under the terms of the agreement, the Company paid $9.0 million in cash consideration and assumed $18.0 million in debt (for further information refer to Note 4 of the Annual Consolidated Financial Statements).

On December 30, 2021, the Company also entered into an agreement to acquire the 35% W.I. in the El Dificil block held by PCR for a total aggregate cash consideration of approximately $13 million. The PCR transaction is expected to close in the second half of 2022 and is subject to customary closing conditions, including but not limited to the prior approval of the assignment by the ANH.

The Company's 100% W.I. in the El Dificil block (transfer of the 35% W.I. is pending for approval by the ANH as described above), combined with PetroSud's interests in the Entrerrios and Rio Meta blocks, is expected to add approximately 1,800 boe/d of total production (1,300 boe/d through the PetroSud acquisition since January 2022 and 500 boe/d when the transaction with PCR closes). The production mix consists of approximately 7.7 Mcf/d of conventional natural gas, 120 boe/d of natural gas liquids, 260 bbl/d of heavy crude oil and 60 bbl/d of light and medium crude oil. Production costs associated with the acquired assets are expected to be $7.50-$8.50/boe. Frontera's acquisition of W.I. in the El Dificil block supports the Company's strategy to increase gas production, lower carbon emissions and include strategically located, high quality gas facilities.

Selected Quarterly Information

Operational and financial results		2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1
Heavy crude oil production	(bbl/d)	20,912	18,168	17,241	20,997	21,074	21,997	22,533	31,996
Light and medium crude oil production	(bbl/d)	16,300	17,160	17,142	18,294	19,502	19,550	18,107	28,959
Total crude oil production	(bbl/d)	37,212	35,328	34,383	39,291	40,576	41,547	40,640	60,955
Conventional natural gas production	(mcf/d)	4,663	5,033	5,164	5,227	6,356	7,895	9,399	11,611
Natural gas liquids	(boe/d)	575	211	393	391	254	270	308	580
Total production	(boe/d)	38,605	36,422	35,682	40,599	41,945	43,202	42,597	63,572
Sales volumes, net of purchases (D&P) (1)	(boe/d)	39,001	26,672	34,151	34,555	44,551	39,966	35,963	34,186
Brent price	($/bbl)	79.66	73.23	69.08	61.32	45.26	43.34	33.39	50.82
Oil and gas sales, net of purchases (1)	($/boe)	75.12	67.13	64.54	58.18	42.20	40.18	24.96	41.57
Realized (loss) gain on risk management contracts	($/boe)	(1.87)	(2.68)	(8.00)	(3.53)	(2.00)	(1.70)	12.19	2.65
Royalties	($/boe)	(3.62)	(4.83)	(0.53)	(1.96)	(0.47)	(0.23)	—	(1.18)
Dilution costs (2)	($/boe)	(0.10)	(0.15)	(0.34)	(2.25)	(1.85)	(1.62)	(2.63)	(1.36)
Net sales realized price (2)	($/boe)	69.53	59.47	55.67	50.44	37.88	36.63	34.52	41.68
Production costs (2)	($/boe)	(12.71)	(11.44)	(11.72)	(10.06)	(12.95)	(8.55)	(8.68)	(12.12)
Transportation costs (2)	($/boe)	(9.02)	(10.24)	(11.15)	(11.30)	(11.36)	(10.24)	(11.56)	(12.75)
Operating netback	($/boe)	47.80	37.79	32.80	29.08	13.57	17.84	14.28	16.81
Revenue	($M)	301,969	182,673	224,685	184,734	177,109	152,760	81,701	236,938
Net income (loss)	($M)	629,376	38,531	(25,648)	(14,126)	48,636	(90,473)	(67,760)	(387,809)
Per share – basic ($)	($)	6.60	0.40	(0.26)	(0.14)	0.50	(0.93)	(0.70)	(4.04)
Per share – diluted ($)	($)	6.40	0.39	(0.26)	(0.14)	0.48	(0.93)	(0.70)	(4.04)
General and administrative	($M)	12,144	12,656	14,132	13,202	19,851	10,539	9,716	15,015
Operating EBITDA	($M)	148,323	72,646	83,072	69,158	35,639	52,113	37,608	46,982
Capital expenditures	($M)	135,458	103,220	61,214	14,365	24,871	2,905	15,651	64,676

1.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 new operating netback approach. Refer to the “Non-IFRS Measures” section on page 22 for further details.

2. 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. In addition, lower production volumes due to natural declines in its mature fields, since the second quarter of 2020, there was a significant reduction in production resulting from the voluntary shut-in of production from certain blocks due to the low global crude oil price environment and the impact of the COVID-19 pandemic, significant reduction in capital spending, the cessation of production in Peru since March 2020, and reductions of water disposal volumes at Quifa during 2021; however, since the third quarter of 2021, the Company has slightly increased its production. In addition, there has been a reduction in transportation costs since early 2020 due to the cessation of payments for unused facilities under the Ancillary Agreements that were settled as part of the implementation of the Conciliation Agreement (refer to the “Conciliation Agreement” section on page 29).

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 IVI and the disposal of the Company’s 43.03% W.I. in Bicentenario, recognition of provisions related to the Conciliation Agreement (refer to the “Conciliation Agreement” section on page 29 for further details), DD&A, and total (loss) gain from risk management contracts that fluctuate with changes in hedging strategies and crude oil benchmark forward prices. Refer to the Company’s previously issued annual and interim Management Discussion and Analysis available on SEDAR at www.sedar.com for further information regarding changes in prior quarters.

Selected Annual Information

($M, except as noted)	As at and for the year ended December 31 2021	2020	2019
Revenue	894,061	648,508	1,383,577
Net income (loss) attributable to equity holders of the Company	628,133	(497,406)	294,287
Per share – basic ($)	6.50	(5.13)	3.01
Per share – diluted ($)	6.29	(5.13)	2.96
Cash and cash equivalents	257,504	232,288	328,433
Total assets	2,611,080	2,063,912	2,492,751
Total non-current liabilities	566,144	567,241	639,460
Total liabilities	1,162,189	1,299,080	1,222,717

Revenue increased to $0.9 billion in 2021 from $0.6 billion in 2020, and decreased from $1.4 billion in 2019. The revenue increase between 2021 and 2020 was mainly due to higher crude oil prices, and between 2020 and 2019, the decrease was mainly due to the reduction in global crude oil prices and production volumes.

Net income for 2021 was $628.1 million, compared to a net loss of $497.4 million in 2020 and a net income of $294.3 million in 2019, as a result of recognition and derecognition of deferred income taxes and impairment or reversal of impairment of oil and gas assets, loss from the acquisition of IVI, higher operating EBITDA, and loss from the Conciliation Agreement. Refer to the “Conciliation Agreement” section on page 29 for further details.

Total assets increased to $2.6 billion in 2021 from $2.1 billion in 2020 and $2.5 billion in 2019, mainly as a result of the reactivation of investment activities and reversal of impairment in oil and gas properties in 2021.

Cash and cash equivalents increased to $257.5 million in 2021 from $232.3 million in 2020, as a result of a higher cash flows from operations and the release of restricted cash in 2021, and decreased from $328.4 million in 2019, mainly due to the decline in oil prices during 2020.

Midstream Activities

The Company has investments in certain infrastructure and midstream assets which includes 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 which consists 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 pipelines. Results of operations from these pipelines are not significant to the Company’s consolidated financial results.
2. Interest are both direct and indirect
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 August 6, 2020, the Company increased its ownership of IVI (the entity that directly and indirectly controlled Puerto Bahia) from 39.22% to 71.57%, and as a result, the Company began to consolidate Puerto Bahia. Subsequently, on December 30, 2020, and December 23, 2021, the Company increased its ownership in Puerto Bahia to 94.16% and 96.55%, respectively, through the conversion of certain debt held by the Company’s subsidiaries Frontera Bahia, IVI, and Frontera Colombia AG into preferred shares with voting rights.

For the year ended December 31, 2021, Puerto Bahia has generated $39.7 million of segment income from operations (2020: $13.8 million since acquisition date on August 6, 2020) primarily from take-or-pay contracts in its liquid bulk storage terminal business. Prior to the acquisition of a controlling interest in Puerto Bahia the Company recognized $18.0 million as its share of losses from IVI mainly due to higher unrealized foreign exchange losses on the revaluation of Puerto Bahia’s USD-denominated bank debt.

ODL Pipeline

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

For the year ended December 31, 2021, the Company recognized $38.0 million as its share of income from ODL, which was $4.2 million lower than the same period of 2020 primarily due to a decrease in the transportation tariff since the second quarter 2020 and the impact of foreign exchange fluctuations. During the year ended December 31, 2021, the Company recognized gross dividends of $41.6 million (2020: $42.0 million) and a return of capital of $4.2 million (2020: $Nil).

Guyana Port Project

CGX, 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 with containerized and specialized cargo handling and agricultural import/export operations (the “Guyana Port Project”). The land for the Guyana Port Project was leased until through to 2060, and is renewable for an additional term of 50 years. For the year ended December 31, 2021, CGX invested $6.4 million in the Guyana Port Project and the construction had no impact on the Company's income statement.

Bicentenario Pipeline (“BIC Pipeline”)

On November 11, 2021, the Company, Bicentenario, and Cenit, completed the Conciliation Agreement pursuant to which the Company transferred its 43.03% interest in Bicentenario, which owns the BIC Pipeline. As a result, the Company recognized the disposal of the investment, and $103.6 million corresponding to the CTA investment. Refer to the “Conciliation Agreement” section on page 29 for further details.

Midstream Segment Results

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

	Three months ended December 31		Year ended December 31	
($M)	**2021**	**2020**	**2021**	**2020**
Revenue	19,186	16,733	72,085	28,056
Costs	(5,038)	(5,615)	(19,779)	(8,767)
General and administrative expenses	(1,987)	(2,093)	(6,537)	(3,328)
Depletion, depreciation and amortization	(2,013)	(414)	(4,924)	(2,187)
Restructuring, severance and other costs	(400)	—	(978)	—
Segment income from operations	**9,603**	**8,611**	**39,722**	**13,774**
Share of Income from associates - ODL	9,751	10,730	38,033	42,214
Share of Income from associates - Bicentenario	—	2,694	—	19,355
Share of income (loss) from associates - IVI	—	—	—	(18,024)
Segment income	**19,354**	**22,035**	**77,755**	**57,319**

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 (as defined below). Refer to the “Liquidity and Capital Resources” section on page 25.

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, costs under terminated pipeline 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 December 31		Year ended December 31	
($M)	**2021**	**2020**	**2021**	**2020**
Net income (loss)	629,376	48,636	628,133	(497,406)
Finance income	(30)	(6,665)	(5,362)	(19,529)
Finance expenses	11,768	18,778	51,822	58,421
Income tax (recovery) expense	(36,118)	(143,756)	1,039	33,284
Depletion, depreciation and amortization	20,121	51,637	126,692	258,867
Impairment (reversal) expense and others	(562,520)	(14,430)	(565,523)	137,513
Costs under terminated pipeline contracts	(4,386)	99,058	(4,386)	118,679
Share-based compensation non cash portion	2,973	1,181	6,695	3,960
Restructuring, severance and other costs	1,746	7,340	4,616	21,097
Share of income from associates	(9,751)	(13,422)	(38,033)	(43,545)
Foreign exchange loss (gain)	11,128	(27,840)	35,510	7,742
Other (income) loss, net	(14,788)	3,043	(1,435)	47,328
Unrealized (gain) loss on risk management contracts	(4,530)	(741)	(7,213)	6,481
Non-controlling interests	(265)	12,820	7,933	15,494
Loss on extinguishment of debt	—	—	29,112	—
Reclassification of currency translation adjustments	103,599	—	103,599	23,956
Operating EBITDA	**148,323**	**35,639**	**373,199**	**172,342**

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 12.

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 11.

The following is a description of each component of the Company's operating netback and how it is calculated.

Oil and gas sales, net of purchases, 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 from D&P assets, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2021	2020	2021	2020
Oil and gas sales ($M) [1]	306,701	173,047	898,518	648,060
(-) Cost of purchases ($M) [2]	(37,176)	(67)	(82,725)	(2,712)
Oil and gas sales, net of purchases ($M)	**269,525**	**172,980**	**815,793**	**645,348**
Sales volumes, net of purchases (D&P) - (boe)	3,588,117	4,098,692	12,259,620	16,891,998
Oil and gas sales, net of purchases ($/boe)	75.12	42.20	66.54	38.20

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 21.
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 from D&P assets, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2021	2020	2021	2020
Net sales ($M)	249,491	155,266	725,329	646,498
Sales volumes, net of purchases (D&P) - (boe)	3,588,117	4,098,692	12,259,620	16,891,998
Net sales realized price ($/boe)	69.53	37.88	59.15	38.27

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 December 31		Year ended December 31	
	2021	2020	2021	2020
Production costs ($M)	45,137	49,976	158,252	187,741
Production (boe)	3,551,660	3,858,940	13,803,205	17,494,800
Production costs ($/boe)	12.71	12.95	11.46	10.73

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 December 31		Year ended December 31	
	2021	2020	2021	2020
Transportation costs ($M)	29,225	40,882	132,029	188,039
Net production (boe)	3,239,504	3,599,684	12,662,215	16,206,480
Transportation costs ($/boe)	9.02	11.36	10.43	11.60

Consolidated Total Indebtedness and Net Debt

Consolidated total indebtedness and net debt are used by the Company to monitor its capital structure, financial leverage, and as a measure of overall financial strength. Consolidated total indebtedness is defined as long-term debt, plus liabilities for leases and net position of risk management contracts, excluding the Unrestricted Subsidiaries. This metric is consistent with the definition under the Indenture for the calculation of certain conditions and covenants. Net debt is defined as consolidated total indebtedness less cash and cash equivalents. Both measures are exclusive of non-recourse subsidiary debt and certain amounts attributable to the Unrestricted Subsidiaries.

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

($M)	As at December 31 2021
Long-term debt [1]	$ 409,468
Total lease liabilities [2]	7,134
Risk management liabilities, net [3]	281
Consolidated Total Indebtedness	**416,883**
(-) Cash and Cash Equivalents [4]	(209,305)
(=) Net Debt	**$ 207,578**

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 $6.3 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.

6. LIQUIDITY AND CAPITAL RESOURCES

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

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

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

As of December 31, 2021, the Company had a total cash balance of $320.8 million (including $63.3 million in restricted cash), which is $80.4 million lower than December 31, 2020. For the year ended December 31, 2021, the Company generated $327.4 million in operating cash flows which were used to fund cash outflows of $186.9 million for capital expenditures and other investing activities (including the acquisition of PetroSud). For the year ended December 31, 2021, financing activities generated net outflows of $108.4 million as a result of the repayment of $373.3 million for the 2023 Unsecured Notes (as defined below), the transaction cost associated with the 2028 Unsecured Notes (as defined below), $43.5 million of interest and other financing charges, $40.0 million of 2025 Puerto Bahia Debt payments, $21.5 million in Common Shares repurchased, $11.7 million in lease payments, and $15.7 million of dividends paid to non-controlling interest, partially offset by a net cash inflow of $397.4 million ($400 million in issuances minus $2.6 million of issue price) from the 2028 Unsecured Notes. As a result, the working capital deficit was reduced to $78.9 million at the year-end 2021 compared with $111.7 million at year-end 2020.

Since the third quarter of 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 December 31, 2021) classified as a current liability (for further information on the 2025 Puerto Bahia Debt, refer to page 27 and Note 19 of the 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 December 31, 2021, the main components of restricted cash were long-term abandonment funds as required by the ANH, and restricted funds related to the 2025 Puerto Bahia Debt. Abandonment funds will satisfy abandonment obligations and are expected to be released in the long term as assets are abandoned. Abandonment funding requirements are updated annually, typically during the third quarter, and can be satisfied through additional allocations of restricted cash, designation of letters of credit, or a combination of both. As of December 31, 2021, the Company had total restricted cash of $63.3 million, a decrease of $105.6 million from December 31, 2020, primarily due to $36.8 million lower cash collateral requirements of exploration commitments, $35.7 million of abandonment funds being replaced with letters of credit, $15.5 million being released after certain legal processes closed, $29.4 million being released as part of the Conciliation Agreement (refer to the "Conciliation Agreement" section on page 29 for further details) and foreign exchange fluctuations, which were partially offset by an increase of $13.0 million in the Puerto Bahia debt reserve account according to the 2025 Puerto Bahia Debt contract.

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 will 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 32.

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 December 31, 2021, the Company is in compliance with all such covenants.

As of December 31, 2021, and pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $416,883,000 consolidated adjusted EBITDA of $373,202,000 and consolidated interest expense of $31,181,000.

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 22.

   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 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. 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 December 31, 2021, 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 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 December 31, 2021, the PetroSud Debt outstanding amount is $18.0 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 December 31, 2021, PetroSud is in compliance with all such covenants.

Letters of Credit

The Company has various uncommitted bilateral letters of credit lines. As of December 31, 2021, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $82.8 million (total credit lines of $89.6 million), without cash collateral, an increase of $62.7 million compared to December 31, 2020. Subsequent to December 31, 2021, the Company increased its credit lines by approximately $16.0 million.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at December 31, 2021, undiscounted by calendar year, are presented below:

As at December 31, 2021 ($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	5,229	2,922	92	57	—	—	8,300
2025 Puerto Bahía Debt and interest (1)	46,916	50,120	47,723	13,269	—	—	158,028
PetroSud Debt and interest	4,481	14,994					19,475
Total financial obligations	**$ 88,126**	**$ 99,536**	**$ 79,315**	**$ 44,826**	**$ 31,500**	**$ 447,250**	**$ 790,553**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	$ 70,117	$ 70,117	$ 70,117	$ 35,016	$ —	$ —	$ 245,367
ODL agreements	15,842	14,855	14,855	11,164	—	—	56,716
Other transportation and processing commitments	12,204	11,785	11,785	11,785	11,785	4,923	64,267
Exploration commitments							
Minimum work commitments (2)	69,545	89,832	28,759	19,285	—	—	207,421
Other commitments							
Operating purchases, leases and community obligations	35,415	9,476	8,473	7,946	249	1,322	62,881
Total Commitments	**$ 203,123**	**$ 196,065**	**$ 133,989**	**$ 85,196**	**$ 12,034**	**$ 6,245**	**$ 636,652**

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 should 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 December 31, 2021, 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.
- The Company holds a 47.73% indirect interest in Berbice block through its 76.98% interest in CGX, which has an indirect interest held through its 62.0% interest in ON Energy Inc. ("**ON Energy**"), the holder of the petroleum licenses related to the block. On February 4, 2022, ON Energy notified the Guyana Ministry of Natural Resources that, given the focus on the Corentyne block, operational considerations and investment priorities, ON Energy is unable to complete the seismic program on the Berbice block in 2022, proposed that seismic acquisition on the block be shifted to commence in January 2023 and therefore seeks the Minister's urgent guidance on this matter. On February 21, 2022, the Minister of Natural Resources informed ON Energy that it must drill one commitment exploration well and acquire seismic on the Berbice block prior to the expiry of the Berbice petroleum prospecting license and associated petroleum agreement in February 2023. CGX will seek further dialogue with the Ministry of Natural Resources regarding this guidance.

The CGX (operator) and Frontera joint venture, has entered into agreements for activities to complete requirements under the Corentyne and Demerara contracts. Also, CGX, has entered into agreements for the Guyana Port Project. As at December 31, 2021, aggregate minimum future obligation still outstanding under these agreements is $32.1 million expected to be paid in 2022. 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.

Acquisition of 35% Interest in El Dificil Block

The Company, through its acquisition of PetroSud (for further information refer to Note 4 of the Annual Consolidated Financial Statements), acquired a 65% W.I. in the El Dificil block. On December 30, 2021, the Company entered into an agreement to acquire the remaining 35% W.I. in the El Dificil block held by PCR. The latter is expected to close during 2022 and is subject to customary closing conditions, including the prior approval of the assignment by the ANH. Upon completion of the transaction, the Company will hold a 100% W.I.in the El Dificil block.

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, including $1.6 million to cover outstanding Muisca cash calls, and $0.2 million of operating cash of M&P. Additionally, the Company will fund $6.0 million related to outstanding commitments at COR-15 during the first half of 2022. EMP and the Company settled all mutual obligations and granted certain indemnities to M&P. This transaction decreased an estimated of $17.2 million of the Company’s exploration obligations.

Other Guarantees and Pledge

As part of the Company´s acquisition of Repsol Colombia Oil & Gas Ltd. (“**RCOG**”) 50% W.I. in the CPE-6 block, Frontera Colombia granted a pledge to RCOG over the production from the CPE-6 block to guarantee the variable payments under the farm-out agreement, up to a maximum of $48.0 million, which are calculated and contingent on production from this block. As at December 31, 2021, the Company has paid a total of $5.1 million of such amounts under the agreement.

On April 29, 2020, Oleoducto Central S.A. (“**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.

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.

Termination of Transportation Agreement Dispute

Conciliation Agreement

On November 16, 2020, Frontera, Cenit and Bicentenario reached an agreement for the joint filing of a petition for approval of the Conciliation Agreement to resolve all the disputes among them related to the BIC Pipeline and the CLC Pipeline, and to terminate all arbitration proceedings related to such disputes.

The Conciliation Agreement included a full and final mutual release upon closing of all present and future amounts claimed by all parties in respect of the terminated transportation agreements and ancillary agreements, related to the BIC Pipeline and the CLC Pipeline which amounts included the liabilities that are recorded by Frontera as Cost Under Terminated Pipeline Contracts in the Company’s financial statements.

The transaction did not include any cash payments between the parties, except for the Company’s release of its interests in a trust fund (restricted cash) including interest, created as a collateral for one of the claims. Upon completion of the settlement, Frontera transferred to CENIT its 43.03% interest in Bicentenario, any related outstanding Bicentenario dividends, and the BIC Pipeline line fill. The claims released by the Company included recovery of the letters of credit drawn by Bicentenario in 2018 and all other claims that had been asserted by the Company against Bicentenario.

The arrangement was conditional upon approval of the Conciliation Agreement under Colombian law, which required an opinion to be issued by the Office of the Attorney General of Colombia (Procuraduria General de la Nacion) and approval of the Administrative Tribunal of Cundinamarca (the “**Court**”), the final appeals court with competence regarding conciliation arrangements to which state-owned companies are a party. On November 17, 2020, the Conciliation Agreement was filed with the Office of the Attorney General of Colombia.

On November 11, 2021, the Court approved the Conciliation Agreement and the final formalities of the settlement arrangement were concluded. This represented the final step in resolving all disputes between the parties related to the BIC Pipeline and the CLC Pipeline and terminated all pending arbitration proceedings related to such disputes.

As part of the conciliation, the Company recognized (i) $3.6 million prepaid transportation services, (ii) $4.4 million recovery of Costs Under Terminated Pipeline Contracts, and (iii) $103.6 million non-cash loss related to currency translation differences reclassified from Other Reserves to the Statement of Income (Loss) Income.

During the year ended December 31, 2020, as result of the Conciliation Agreement, the Company recognized $118.7 million as cost under terminated pipeline contracts in the Consolidated Statement of Income (Loss), which represented the fair value of the assets to be transferred or release, offset by previous contingent liabilities related with the claim in respect of the terminated transportation contracts.

New Transportation Agreements

In connection with the closing of the settlement, the Company also entered into new transportation contracts with Cenit and Bicentenario and a new transportation contract with ODL:

- The new transportation contracts with Cenit and Bicentenario for use of the CLC Pipeline and BIC Pipeline (and certain related facilities) will be for approximately 2,770 bbls/day, and become effective within a six-month period following the Conciliation Agreement´s approval.
- The new ODL transportation contract provides for a ship or pay commitment of 10,000 bbls/day for approximately 3.8 years years at a current tariff of $3.99/bbl..

For further information on the claims settled pursuant to the Conciliation Agreement, see "Note 27 – Commitments and Contingencies" of the 2021 Annual Financial Statements.

Quifa Late Delivery Volumes Claim

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

In March 2021, the Company received notification that the Court had decided in favour of Ecopetrol and awarded $8.5 million adjusted by the Consumer Price Index. The Company has filed an appeal against the first instance ruling on March 16, 2021. During the first quarter of 2021, the Company recorded a provision of $9.3 million included within Other Loss.

ANH Discussion

Since May 8, 2020, the Company has been discussing with the ANH the termination of certain exploratory contracts due to environmental, social and security restrictions in the contracted areas, not allowing the Company to execute exploratory commitments for $26.2 million.

On December 12, 2021, the Company informed the ANH that the outstanding commitments under the LLA-7 and LLA-55 of $26.2 million were going to be credited by means of drilling exploration wells in other blocks, as provided under the recent regulation issued by the ANH (Acuerdo 10 of 2021). When the Company completes the proposed activities obligations will no longer be outstanding.

High-Price Clause

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

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

Ecopetrol - Rubiales Field Disagreement

The Company has been involved in negotiations with Ecopetrol with respect to disagreements on wind-down costs and expenses, as well as inventory, in connection with the expiration of the Rubiales and Piriri exploration and production contracts in June 2016. On November 22, 2018, the Company filed a lawsuit against Ecopetrol before the Court claiming it is owed $25.3 million. The Company was formally notified by Ecopetrol that they had filed a lawsuit against the Company for over $45.0 million. As this time, the Company has not yet been served such claim and negotiations continue; therefore, the Company cannot anticipate what the outcome of this proceeding will be or whether the final settled net amount will be significant.

Tax reviews

The Company operates in various jurisdictions and is subject to assessments by tax authorities in each of those jurisdictions, which can be complex and based on interpretations. The Company is currently in discussions with tax authorities for various assessments with respect to certain income tax deductions relating to exploitation costs, transportation costs, VAT credits, municipal taxes, and other expenses. As at December 31, 2021, the Company has assessed a possible tax exposure (worst case scenario) of $101.4 million, ($253.1 million as at December 31, 2020) relating to these assessment for taxes, interest and penalties.

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 1, 2021:

	Number
Common shares	94,499,994
Deferred share units ("**DSUs**") [1]	766,737
Restricted share units ("**RSUs**") [2]	1,978,888

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, 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 Compensation and Human Resources Committee of the Board in its sole discretion and specified in the award agreement pursuant to which the RSU is granted.

Dividends

The Company suspended its quarterly dividend due to the oil price decline since first quarter of 2020. Prior to the suspension, the Company paid dividends during 2020 as presented in the table below. The declaration and payment of any specific dividend, including the actual amount, declaration date and record date are subject to the discretion of the Board of Directors. In response to the volatility in oil prices, the Company has not reinstated its quarterly dividend but intends to utilize share repurchases under its NCIB as described below.

Declaration Date	Record Date	Payment Date	Dividend (C$/Share)	Dividends Amount ($M)	Number of DRIP Shares [1]
November 7, 2019	January 3, 2020	January 17, 2020	0.205	15,125	474,568
March 5, 2020	April 2, 2020	April 16, 2020	0.205	13,966	1,679,065
Total			0.410	29,091	2,153,633

1. The Company has a dividend reinvestment program ("**DRIP**") to provide shareholders who are resident in Canada with the option to have the cash dividends declared on their Common Shares reinvested automatically back into additional Common Shares, without the payment of brokerage commissions or service charges.

Normal Course Issuer Bid

On March 15, 2021, the TSX approved the Company´s notice to initiate a NCIB for its Common Shares. Pursuant to the NCIB, the Company may purchase for cancellation up to 5,197,612 of its Common Shares during the 12-month period commencing March 17, 2021 and ending March 16, 2022, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules) as at March 11, 2021. 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 the automatic share purchase plan and applicable regulatory requirements. During the three months and year ended December 31, 2021, the Company purchased 989,300 and 3,855,400 Common Shares, respectively, under the NCIB. As at March 1, 2022, the Company had repurchased for cancellation a total of 4,051,100 Common Shares for $23.0 million with an additional 1,146,512 Common Shares available for repurchase under the NCIB.

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

	Year ended December 31	
	2021	2020
Number of common shares repurchased	3,855,400	1,392,314
Total amount of common shares repurchased ($M)	21,537	10,075
Weighted-average price per share ($)	5.59	7.24

8. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding (before impairment), commitments and transactional amounts with related parties, as at December 31, 2021 and 2020, and for the three months and year ended December 31, 2021 and 2020, respectively:

($M)		Accounts Receivable	Accounts Payable	Commitments	Cash Advance
ODL	2021	$ —	$ 112	$ 56,716	$ —
	2020	465	7,821	7,888	—
Bicentenario [1]	2021	—	—	—	—
	2020	$ 70,761	$ —	$ —	$ 87,278

($M)		Three months ended December 31			Year Ended December 31	
		Sales	Purchases / Services	Interest Income [1]	Purchases / Services	Interest Income [1]
ODL	2021	$ —	$ 6,030	$ —	$ 27,523	$ —
	2020	—	7,784	—	35,903	—
Bicentenario	2021	—	—	—	—	—
	2020	—	—	—	1,427	—
IVI [2]	2021	—	—	—	—	—
	2020	$ —	$ —	$ —	$ 22,479	$ 10,558

1. Services related to ship-or-pay contracts the Company previously had with Bicentenario for the transportation of crude oil in Colombia through the Bicentenario Pipeline. The Company also had advances with Bicentenario as a prepayment of transportation tariffs, which were to be amortized against future barrels transported. On November 16, 2020, the Company signed the Conciliation Agreement with Bicentenario. On November 11, 2021, the Conciliation Agreement was settled, resolving all disputes between Bicentenario and the Company (refer to the "Conciliation Agreement" section on page 29 for further details). The accounts receivable and cash advance were fully impairment and not impact were recognized.
2. Transactions before the Company acquired control of IVI on August 6, 2020.

9. RISKS AND UNCERTAINTIES

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

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

For a comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the AIF and Annual Consolidated Financial Statements as of December 31, 2021, copies of which are available on SEDAR at www.sedar.com.

Significant Risk Factors

Production

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

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

Liquidity/Financial

The Company is exposed to normal financial risks inherent in the oil and natural gas industry, including liquidity risk, commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company's principal liquidity and capital resource requirements are capital expenditures for exploration and development, operating expenses, debt services and shareholder returns (such as dividends). The Company funds these requirements through current cash and working capital balances which are carefully managed to ensure that operational needs and other financial obligations are met. For further information on liquidity and capital risk mitigation see section "Liquidity and Capital Resources" on page 25.

The Company also continuously monitors opportunities to use financial instruments such as derivatives to manage exposure to fluctuations in commodity prices and interest rate. For further information see the sections "Risk Management Contracts - Brent Crude Oil" section on page 16 and "Risk Management Contracts - Interest Rate Swap (2025 Puerto Bahia Debt)" section on page 17.

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

Health, Safety and Environmental

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

Exploration, New Business and Reserves Growth

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

Information Security

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

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

Political Risks

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

COVID-19 Pandemic

The COVID-19 pandemic, and related government responses, have had and could continue to have a negative impact on the Company’s financial condition, results of operations, and cash flows. Despite successful vaccine rollouts in many jurisdictions, the risk of a resurgence or additional variant strains remains high and could impact the health and safety of the Company’s employees and contractors; require the temporary suspension of operations in geographic locations in which the Company operates; create operational restrictions; delay the completion of or result in the deferral of growth and expansion projects; create counterparty credit risk; result in continued supply chain disruptions; and result in continued volatility in financial and commodity markets, including fluctuations in the price of oil and natural gas products.

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

The full extent, effect and duration of such events on the Company’s business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events have had, and could continue to have, a material adverse effect on the Company’s business, financial condition and results of operations. Even after the COVID-19 pandemic has subsided, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic’s global economic impact, long-term implications and risk of resurgences. To the extent that the COVID-19 pandemic adversely affects the Company’s business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described herein and in the Company’s AIF.

See the “Liquidity and Capital Resources” section on page 25 for additional detail on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

The list above does not contain all the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, please see the Company’s AIF and Annual Consolidated Financial Statements which are available on SEDAR at www.sedar.com.

10. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

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

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

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

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

The effect of the COVID-19 pandemic on the world economy, 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 Annual Consolidated Financial Statements.

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

11. INTERNAL CONTROL

In accordance with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Annual Filings". This Certification requires certifying officers to certify, among other things, that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Controls over Financial Reporting ("**ICFR**") as those terms are defined in NI 52-109. The control framework used to design the Company's ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations. Additionally, in 2021, 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 and budget restrictions, cyber threats, IT help desk services response time, health and safety, impairment and going concern. While there were no changes made to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting, the Company will continue to monitor and mitigate the risks associated with any changes to its control environment in response to COVID-19 pandemic.

Management has evaluated the effectiveness of the Company's ICFR as at December 31, 2021.

Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at December 31, 2021.

There have been no changes in the Company's ICFR during the quarter ended December 31, 2021, that have materially affected, or are reasonably likely to materially affect, its ICFR.
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 one year 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.

Further integration will take place throughout the year 2022 as processes and systems align. Assets attributable to PetroSud as at December 31, 2021 represented approximately 2% of the Company's total assets, and no revenues were consolidated for the year ended December 31, 2021 (for further information refer to Note 4 of the 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.

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

Based on management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and its Chief Financial Officer, concluded that the Company's DC&P were effective as at December 31, 2021.

12. FURTHER DISCLOSURES

Production Reporting

Production volumes are reported on a Company's working interest before royalties basis, including total volumes produced from service contracts. The latter refers to the total volumes produced under an oil extraction services contract with Perupetro on Block 192 in Peru which expired on February 5, 2021. Under this contract, the volumes produced were owned by Perupetro and the Company was entitled to in-kind payments on production, which ranged from 44% to 84% of production on the block. The Company reported the 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		**Q4 2021**	**Q3 2021**	**Q4 2020**	**FY 2021**	**FY 2020**
Heavy crude oil	(bbl/d)	18,099	15,986	19,694	17,371	22,553
Light and medium crude oil	(bbl/d)	15,721	15,907	18,064	16,046	18,712
Conventional natural gas	(mcf/d)	4,663	5,033	6,356	5,022	8,807
Natural gas liquids	(boe/d)	575	211	254	393	352
Net production Colombia	**(boe/d)**	**35,213**	**32,987**	**39,127**	**34,691**	**43,162**
Producing blocks in Peru						
Light and medium crude oil	(bbl/d)	—	—	—	—	1,118
Net production Peru (1)	**(bbl/d)**	**—**	**—**	**—**	**—**	**1,118**
Total net production	**(boe/d)**	**35,213**	**32,987**	**39,127**	**34,691**	**44,280**

1. On February 27, 2020, Block 192 was placed in force majeure as a result of a community blockade, no production in Peru was reported after the force majeure. Subsequently, on February 5, 2021, the service contract for Block 192 expired.

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 12.

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	**$**	U.S. dollars
D&P	Development and producing	**$M**	Thousand U.S. dollars
E&E	Exploration and evaluation	**$MM**	Million U.S. dollars
MMbbl	Millions of oil barrels	**P1**	Proved reserves
MMboe	Millions of barrels of oil equivalent	**P2**	Probable reserves
Mcf	Thousand cubic feet	**2P**	Proved reserves + Probable reserves