MANAGEMENT DISCUSSION & ANALYSIS

August 10, 2021
For the three and six months ended June 30, 2021

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*Frontera Energy Corporation ("**Frontera**" or the "**Company**") is an oil and gas company formed and existing under the laws of British Columbia, Canada, that is engaged in the exploration, development and production of crude oil and natural gas in South America, and is committed to working hand in hand with all its stakeholders to conduct business in a socially and environmentally responsible manner. The Company's Common Shares ("**Common Shares**") are listed and publicly traded on the Toronto Stock Exchange ("**TSX**") under the trading symbol "FEC." The Company's head office is located at 2000, 350 - 7th Avenue SW Calgary, Alberta, Canada, T2P 3N9.*

Legal Notice – Forward-Looking Information and Statements

*This Management Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Condensed Consolidated Financial Statements and related notes for the three and six months ended June 30, 2021 and 2020 ("**Interim Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and the Annual Information Form (**"AIF"**), have been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com and on the Company's website at www.fronteraenergy.ca. Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.*

*The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board, unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These measures are described in greater detail under the heading "Non-IFRS Measures" section on page 15.*

Certain statements in this MD&A constitute forward-looking statements or "forward-looking information (collectively, "forward-looking statements") within the meaning of applicable securities legislation, which involve known and unknown risks, uncertainties, and other factors that may cause the actual results, performance or achievements of the Company or industry results to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as "expects," "does not expect," "is expected," "anticipates," "does not anticipate," "plans," "planned," "estimates," "estimated," "projects," "projected," "forecasts," "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal" or "objective." In addition, forward-looking statements often state that certain actions, events or results "may," "could," "would," "might" or "will" be taken, may occur or be achieved. Such forward-looking statements, including, but not limited to, statements with respect to estimates and/or assumptions in respect of the impact of a sustained low oil price environment due to the ongoing impacts of the COVID-19 pandemic, and actions of the Organization of Petroleum Exporting Countries and non-OPEC countries, 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 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 and the impact of the Conciliation Agreement and obtaining regulatory approvals, involve known and unknown risks, uncertainties and other factors that may cause the actual levels of production, costs and results to be materially different from the estimated levels expressed or implied by such forward-looking statements.

The Company currently believes the expectations reflected in these forward-looking statements are reasonable, but cannot assure that such expectations will prove to be correct, and thus, such statements should not be unduly relied upon. These forward-looking statements are made as of the date of this MD&A and the Company disclaims any intent or obligation to update any forward looking statements, whether as a result of new information, future events or otherwise, unless required pursuant to applicable laws. Risk and assumptions that could cause actual results to differ materially from those anticipated in these forward-looking statements are described under the headings "Forward-Looking Information" and "Risk Factors" in the Company's AIF and under the heading "Risks and Uncertainties" in this MD&A. Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors and therefore results may not be as anticipated, estimated or intended.

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

1. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q2 2021	Q1 2021	Q2 2020	Six months ended June 30 2021	Six months ended June 30 2020
Operational Results						
Heavy crude oil production	(bbl/d)	17,241	20,997	22,533	19,108	27,265
Light and medium crude oil production	(bbl/d)	17,535	18,685	18,415	18,107	23,978
Total crude oil production [1]	(bbl/d)	34,776	39,682	40,948	37,215	51,243
Conventional natural gas production [1]	(mcf/d)	5,164	5,227	9,399	5,193	10,505
Total production [2][3]	(boe/d) [4]	35,682	40,599	42,597	38,126	53,086
Oil & gas sales, net of purchases [5]	($/boe)	64.54	58.18	24.96	61.35	35.61
Realized (loss) gain on risk management contracts	($/boe)	(8.00)	(3.53)	12.19	(5.77)	6.07
Royalties	($/boe)	(0.53)	(1.96)	—	(1.25)	(0.76)
Diluent costs	($/boe)	(0.26)	(2.13)	(2.53)	(1.19)	(1.73)
Net sales realized price [6]	($/boe)	55.75	50.56	34.62	53.14	39.19
Production costs [7]	($/boe)	(12.08)	(10.54)	(9.03)	(11.26)	(11.09)
Transportation costs [8]	($/boe)	(10.84)	(10.89)	(11.28)	(10.87)	(11.97)
Operating netback [9]	($/boe)	32.83	29.13	14.31	31.01	16.13
Financial Results						
Oil & gas sales, net of purchases	($M)	200,581	180,956	81,701	381,537	324,536
Realized (loss) gain on risk management contracts	($M)	(24,877)	(10,980)	39,885	(35,857)	55,375
Royalties	($M)	(1,640)	(6,110)	—	(7,750)	(6,900)
Diluent costs	($M)	(803)	(6,614)	(8,273)	(7,417)	(15,741)
Net sales [9]	($M)	173,261	157,252	113,313	330,513	357,270
Net loss [10]	($M)	(25,648)	(14,126)	(67,760)	(39,774)	(455,569)
Per share – basic	($)	(0.26)	(0.14)	(0.70)	(0.41)	(4.72)
Per share – diluted	($)	(0.26)	(0.14)	(0.70)	(0.41)	(4.72)
General and administrative	($M)	14,132	13,202	9,716	27,334	24,731
Operating EBITDA [9]	($M)	84,771	69,158	37,608	153,929	84,590
Cash provided by operating activities	($M)	87,391	47,393	102,256	134,784	148,797
Capital expenditures [11]	($M)	61,214	14,365	15,651	75,579	80,327
Cash and cash equivalents – unrestricted	($M)	358,325	248,237	256,135	358,325	256,135
Restricted cash short and long-term	($M)	128,283	161,230	138,634	128,283	138,634
Total cash	($M)	486,608	409,467	394,769	486,608	394,769
Total debt and lease liabilities	($M)	565,238	534,656	379,790	565,238	379,790
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [12]	($M)	468,424	361,699	373,363	468,424	373,363
Net debt (excluding Unrestricted Subsidiaries) [12]	($M)	138,701	139,327	128,882	138,701	128,882

1. Reference to crude oil or natural gas production in the above table and elsewhere in this MD&A refer to the light and medium crude oil, heavy crude oil, and conventional natural gas, respectively, product types as defined in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities.
2. Represents working interest production before royalties and total volumes produced from service contracts. Refer to the "Further Disclosures" section on page 24.
3. Natural gas liquids have not been presented separately because production for such product type was immaterial to the Company.
4. Boe has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.
5. "Oil & gas sales, net of purchases" is a non-IFRS measure and includes crude oil and natural gas sales, net of the cost of volumes purchased from third-party. For further detail refer to the "Non-IFRS Measures" section on page 15.
6. Per boe is calculated using sales volumes from development and producing ("D&P") assets. Volumes purchased from third parties are excluded.
7. Per boe is calculated using production.
8. Per boe is calculated using net production after royalties.
9. Refer to the "Non-IFRS Measures" section on page 15. This section also includes a description and details for all per boe metrics included in operating netback.
10. Net loss attributable to equity holders of the Company.
11. Capital expenditures includes costs, net of income from exploration and evaluation ("**E&E**") assets.
12. Refer to the "Non-IFRS Measures" section on page 15. ("**Unrestricted Subsidiaries**") include CGX Energy Inc.("**CGX**"), Frontera ODL Holding Corp., including its subsidiary Pipeline Investment Ltd. ("**PIL**"), Frontera BIC Holding, and Frontera Bahía Holding Ltd., including its subsidiary Sociedad Portuaria Puerto Bahía S.A. ("**Puerto Bahia**").

Performance Highlights

Second Quarter of 2021

Frontera made progress on a number of important fronts in the second quarter of 2021. Supported by rising oil prices in the second quarter, Frontera increased its operating EBITDA by 23% to $84.8 million and improved its operating netback by 13% to $32.83/boe, compared to the first quarter of this year. The Company refinanced its debt, bought back 1,525,500 shares under the normal course issuer bid ("NCIB"), secured an acreage extension to the CPE-6 block, reduced its restricted cash position and released its 2020 Sustainability Report and ESG goals. The Company maintained its strong balance sheet, ending the quarter with a total cash position of $486.6 million, including $63.4 million in cash that were utilized to repay the 2023 Bond balance on July 7, 2021 and $128.3 million of restricted cash.

The Company averaged 35,682 boe/d in the second quarter of 2021, compared to 40,599 boe/d in the prior quarter and 42,597 boe/d in the second quarter of 2020. The reduction in production quarter over quarter was due to temporarily reduced water disposal volumes and community concerns which delayed drilling a new injector well at Quifa, slower than anticipated recovery of full production levels at CPE-6 following the lifting of road blockades. These community concerns have now been resolved.

The Company completed an offering of $400 million in senior unsecured notes at a coupon rate of 7.875%, maturing in 2028 (the "2028 Unsecured Notes"). Certain proceeds from the offering were used to repurchase, at a premium, the Company's U.S.$350 million 9.7% senior secured notes due 2023 (the "2023 Unsecured Notes") pursuant to a tender offer. The remaining proceeds will be used for general corporate purposes. The refinancing transaction improved the Company's debt covenants, successfully extended the maturity and reduced the Company's average cost of debt.

The Company recorded a net loss of $25.6 million ($0.26/share), compared with a net loss of $14.1 million ($0.14/share) in the prior quarter and a net loss of $67.8 million ($0.70/share) in the second quarter of 2020. The net loss in the current quarter included a Debt extinguishment costs of $29.1 million, total income tax expense of $37.9 million, a loss on risk management contracts of $17.4 million partially offset by $65.6 million of operating income.

On July 16, 2021, the Company increased the credit line with Banco BTG Pactual S.A. by an additional amount of $15.0 million, these new uncommitted credit line do not require cash collateral as a result Frontera released $9.1 million of restricted cash amounts.

Subsequent to the quarter, the Company revised its production guidance for the year. The Company now expects average daily production of 37,500-39,500 boe/d for the year and anticipates a year end exit rate of over 40,000 boe/d. The Company increased its annual Operating EBITDA guidance to $325-$375 million as a result of stronger Brent prices. The Company also narrowed its total capital expenditure range to $245-$295 million, reflecting the expected costs of the Kawa-1 exploration well offshore Guyana as it continues to consider strategic options.

As of August 10, 2021, 5 rigs were running across Frontera's operations. The company continues to expect this current level of activity and capital spending in line with its narrowed guidance ranges to continue through to the end of 2021. In the second half of this year, the Company anticipates increasing production at Quifa and CPE-6 and drilling the Planadas-1 well at VIM-1 through its joint venture. In addition, the Company will begin drilling the potentially transformational Kawa-1 well offshore Guyana.

Financial and Operational Results

- Production averaged 35,682 boe/d (consisting of 17,535 bbl/d of light crude oil and medium crude oil, 17,241 bbl/d of heavy crude oil and 5,164 Mcf/d of conventional natural gas), compared with 40,599 boe/d (consisting of 18,685 bbl/d of light crude oil and medium crude oil, 20,997 bbl/d of heavy crude oil and 5,227 Mcf/d of conventional natural gas) in the prior quarter and 42,597 boe/d (consisting of 18,415 bbl/d of light crude oil and medium crude oil, 22,533 bbl/d of heavy crude oil and 9,399 Mcf/d of conventional natural gas) in the second quarter of 2020.
- Cash provided by operating activities was $87.4 million, compared with $47.4 million in the prior quarter and $102.3 million in the second quarter of 2020. The Company reported a total cash position of $486.6 million at June 30, 2021, including $63.4 million in cash that were utilized to repay the 2023 Bond balance on July 7, 2021, and $128.3 million of restricted cash. As at June 30, 2020, the total cash position was $394.8 million, including $138.6 million of restricted cash.
- Net loss was $25.6 million ($0.26/share), compared with net loss of $14.1 million ($0.14/share) in the prior quarter and net loss of $67.8 million ($0.70/share) in the second quarter of 2020.
- Capital expenditures were $61.2 million, compared with $14.4 million in the prior quarter and $15.7 million in the second quarter of 2020.

- Operating EBITDA was $84.8 million, compared with $69.2 million in the prior quarter and $37.6 million in the second quarter of 2020.
- Operating netback was $32.83/boe, compared with $29.13/boe in the prior quarter and $14.31/boe in the second quarter of 2020.

2. GUIDANCE

The Company has increased its annual Operating EBITDA guidance by 17% at the midpoint to $325-$375 million from $275-$325 million as a result of changes in the assumptions used for realized oil price, in addition to the changes in transportation cost and operating cost discussed below. The most significant factor impacting higher Operating EBITDA is the stronger than expected Brent benchmark price that have resulted in an increase of this assumption for 2021 to $70/bbl compared to $60/bbl in the original guidance.

Guidance for operating costs are expected to remain unchanged for 2021 but production costs are expected to increase by approximately $0.50/boe to $10.50-$11.50/boe; while transportation costs are expected to decrease by approximately $0.50/boe to $10.00-$11.00/boe.

In addition, the Company revised the exploration capital and production guidance and now expects average daily production of 37,500-39,500 boe/d for the year compared to 40,500-42,500 boe/d. Capital Expenditures guidance was narrowed to $245-$295 million increasing exploration capex range to $115-$130 million reflecting the expected costs of the Kawa-1 exploration well offshore as it continues to consider strategic options.

The following table reports the Company's actual results for the six months period ending June 30, 2021, against the revised and previous guidance.

			2021 Guidance	
		2021 YTD	**Revised**	**Previous**
Average production	(boe/d)	38,126	37,500 to 39,500	40,500 to 42,500
Production costs	($/boe)	11.26	10.5 to 11.5	10.0 to 11.0
Transportation costs	($/boe)	10.87	10.0 to 11.0	10.5 to 11.5
Operating EBITDA (1)	($MM)	153.9	325 to 375	275 to 325
Development capital	($MM)	45.3	110 to 130	110 to 130
Exploration capital	($MM)	27.7	115 to 130	70 to 130
Infrastructure and other capital	($MM)	2.6	20 to 35	20 to 35
Capital expenditures (2)	($MM)	75.6	245 to 295	200 to 295

1. Operating EBITDA in revised guidance is calculated at Brent $70/bbl and COP/USD exchange rate of 3700:1.
2. Capital expenditures guidance does not include decommissioning costs. The Company expects to execute $10 million of decommissioning in 2021, including $4 million in Peru.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

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

		Production				
Producing blocks in Colombia		**Q2 2021**	**Q1 2021**	**Q2 2020**	**YTD 2021**	**YTD 2020**
Heavy oil	(bbl/d)	17,241	20,997	22,533	19,108	27,265
Light and medium oil	(bbl/d)	17,535	18,685	18,415	18,107	21,285
Conventional natural gas production	(mcf/d)	5,164	5,227	9,399	5,193	10,505
Total production Colombia	**(boe/d)**	**35,682**	**40,599**	**42,597**	**38,126**	**50,393**
Producing blocks in Peru						
Light and medium oil	(bbl/d)	—	—	—	—	2,693
Total production Peru	**(bbl/d)**	**—**	**—**	**—**	**—**	**2,693**
Total production	**(boe/d)**	**35,682**	**40,599**	**42,597**	**38,126**	**53,086**

Colombia

Production in Colombia for the three months ended June 30, 2021, decreased by 12% compared to the prior quarter. Heavy oil production decreased compared to the prior quarter due to road blockades, subsequent community unrest at CPE-6 block and reductions of water disposal volumes at Quifa block as the Company voluntarily and temporarily reduced production at the end of the first quarter while it is developing other water disposal options for the benefit of long-term production in the block. In addition Light and Medium oil also decreased mainly due to community-related delays impacting operational activities at Guatiquia block.

Compared to the second quarter of 2020 and first half of 2020, production decreased by 16% and 28%, respectively, as a result of natural decline due to the significant curtailments in drilling activities starting in the second quarter of 2020 and reductions of water disposal volumes at Quifa at the end of the first quarter 2021. The drilling suspension was part of the Company's program to manage the impact of the COVID-19 pandemic and the lower oil price environment during 2020.

Peru

The Company reported no production in Peru for the three and six months ended June 30, 2021 and the second quarter of 2020 compared with 2,693 bbl/d in the first half of 2020. The service contract for Block 192 was suspended in February 2020 with no operations until its expiry on February 5, 2021. The Company continues to sell oil inventory and complete remediation work in the block.

Production Reconciled to Sales Volumes

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

					Six months ended June 30	
		Q2 2021	**Q1 2021**	**Q2 2020**	**2021**	**2020**
Production	(boe/d)	**35,682**	**40,599**	**42,597**	**38,126**	**53,086**
Royalties in-kind Colombia	(boe/d)	(2,904)	(2,762)	(3,048)	(2,833)	(3,700)
Royalties in-kind Peru [1]	(boe/d)	—	—	—	—	(445)
Net production	(boe/d)	**32,778**	**37,837**	**39,549**	**35,293**	**48,941**
Oil inventory draw (build)	(boe/d)	2,352	(751)	(1,917)	809	3,305
(Settlement) overlift	(boe/d)	16	(640)	(13)	(310)	(7)
Volumes purchases	(boe/d)	3,492	577	135	2,043	154
Other inventory movements [2]	(boe/d)	(1,917)	(1,785)	(1,791)	(1,851)	(2,245)
Sales volumes	(boe/d)	**36,721**	**35,238**	**35,963**	**35,984**	**50,148**
Sale of volumes purchased	(boe/d)	(2,570)	(683)	—	(1,632)	(74)
Sales volumes, net of purchases	(boe/d)	**34,151**	**34,555**	**35,963**	**34,352**	**50,074**
Oil sales volumes	(bbl/d)	33,258	33,648	34,320	33,452	48,266
Natural gas sales volumes	(mcf/d)	5,090	5,170	9,365	5,130	10,306
Total oil and natural gas sales volumes, net of purchases	(boe/d)	**34,151**	**34,555**	**35,963**	**34,352**	**50,074**
Inventory balance						
Colombia	(bbl)	488,828	602,536	840,893	488,828	840,893
Peru [3]	(bbl)	480,200	580,499	852,892	480,200	852,892
Inventory ending balance	**(bbl)**	**969,028**	**1,183,035**	**1,693,785**	**969,028**	**1,693,785**

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 bbls in Peru during the first half of 2021 and expects to sell the remaining oil inventory in Peru during 2021.

Sales volumes, net of purchases for the three and six months ended June 30, 2021, decreased by 5% and 31%, respectively, compared with same periods of 2020, primarily due to lower volumes sales in Colombia as consequence of the production decrease. For the three months ended June 30, 2021, sales volumes, net of purchases was similar to the previous period.

Colombia Royalties - PAP

The Company makes PAP payments to Ecopetrol S.A. and the Agencia Nacional de Hidrocarburos ("**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).

		Q2 2021	Q1 2021	Q2 2020	YTD 2021	YTD 2020
PAP in cash	(bbl/d)	234	201	—	218	402
PAP in kind	(bbl/d)	413	19	—	217	130
PAP	**(bbl/d)**	647	**220**	**—**	435	**532**
% Production		**1.8 %**	**0.5 %**	**— %**	**1.1 %**	**1.0 %**

For the three months ended June 30, 2021, PAP increased compared with the previous quarter and the three months ended June 30, 2020 primarily due to higher WTI oil benchmark price. For the six months ended June 30, 2021, PAP decreased compared to the same period of 2020 due to lower production during 2021.

Realized and Reference Prices

		Q2 2021	Q1 2021	Q2 2020	2021	2020
Reference price						
Brent	($/bbl)	69.08	61.32	33.39	65.23	42.10
Average realized prices						
Realized oil price, net of purchases	($/bbl)	65.67	59.15	25.14	62.41	36.13
Realized natural gas price	($/mcf)	3.99	3.96	3.66	3.97	3.76
Net sales realized price						
Oil & gas sales, net of purchases	($/boe)	64.54	58.18	24.96	61.35	35.61
Realized (loss) gain on risk management contracts	($/boe)	(8.00)	(3.53)	12.19	(5.77)	6.07
Royalties	($/boe)	(0.53)	(1.96)	—	(1.25)	(0.76)
Diluent costs	($/boe)	(0.26)	(2.13)	(2.53)	(1.19)	(1.73)
Net sales realized price	**($/boe)**	**55.75**	**50.56**	**34.62**	**53.14**	**39.19**

The average Brent benchmark price during the three and six months ended June 30, 2021, increased by 107% and 55%, respectively, compared to the same periods of 2020. In comparison to the first quarter of 2021, the average Brent benchmark price increase by 13%. The increase in crude oil prices was mostly attributable to a better global economic outlook in the oil demand especially in Asia (China and India) and the vaccine rollouts against COVID-19. OPEC+ kept a modest increase of 500,000 bbls per month that has kept the market tighter than expected. Also Iran has not come out to a nuclear agreement with the US delaying the return of an important amount of barrels to the market.

For the three and six months ended June 30, 2021, the Company's net sales realized price was $55.75/boe and $53.14/boe, respectively, an increase of 61% and 36%, compared to the same periods of 2020 due to the higher Brent benchmark price, narrower differentials, the reduction in diluent costs due to optimization in dilution strategy and partially offset by, realized losses on risk management contracts during 2021 compared to a gain in 2020 and, higher cash royalties resulting from the oil price increase. In comparison to the first quarter of 2021, the net sales realized price increased by 10%, or $5.19/boe, primarily driven by the increase in the benchmark oil price, the reduction in diluent cost explained above. Although royalties of $8.9 million were recognized during the second quarter of 2021, this was partially offset by a reversal of previously recorded provision.

Operating Netback

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

	Q2 2021		Q1 2021		Q2 2020	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1) (2)	173,261	55.75	157,252	50.56	113,313	34.62
Production costs (3)	(39,212)	(12.08)	(38,513)	(10.54)	(34,984)	(9.03)
Transportation costs (4)	(32,343)	(10.84)	(37,084)	(10.89)	(40,606)	(11.28)
Operating Netback (5)	**101,706**	**32.83**	**81,655**	**29.13**	**37,723**	**14.31**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases D&P - (boe) (2) (6)		34,151		34,555		35,963
Production (7)		35,682		40,599		42,597
Net production (8)		32,778		37,837		39,549

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

Operating netback for the second quarter of 2021 was $32.83/boe, compared to $14.31/boe in the same quarter of 2020. The increase was primarily due to higher net sales realized price, and accounting eliminations from the consolidation of Puerto Bahia since the acquisition of control in IVI in the third quarter of 2020. The foregoing was partially offset by, higher production costs primarily as a result of well services executed and reduction in volumes produced during the second quarter of 2021.

In comparison to the first quarter of 2021, operating netback increased from $29.13/boe to $32.83/boe, primarily due to higher net sales realized price partially offset by, higher production costs primarily as a result of well services executed during the second quarter. On a per boe basis the increase is higher due to the reduction in volumes produced during the second quarter of 2021. Despite the challenges generated by the road blockades in Colombia during the second quarter of 2021, the transportation costs did not present significant increases.

The following table provides a summary of the Company's netbacks for the six months ended June 30, 2021:

	Six months ended June 30			
	2021		2020	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1) (2)	330,513	53.14	357,270	39.19
Production costs (3)	(77,725)	(11.26)	(107,194)	(11.09)
Transportation costs (4)	(69,427)	(10.87)	(106,658)	(11.97)
Operating Netback (5)	**183,361**	**31.01**	**143,418**	**16.13**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases D&P - (boe) (2) (6)		34,352		50,074
Production (7)		38,126		53,086
Net production (8)		35,293		48,941

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

Operating netback for the six months ended June 30, 2021, increased by 28% to $31.01/boe from $16.13/boe in the same period of 2020. The increase was primarily due to higher Company's net sales realized price, and reduction of transportation cost due to the cessation of payments for unused facilities under the BIC Ancillary Agreements and the CLC Ancillary Agreements since March 2020 (for further information refer to Note 28 of the Company's audited annual consolidated financial statements for the year ended December 31, 2020 (the "**2020 Annual Consolidated Financial Statements**"), accounting eliminations from the consolidation of Puerto Bahia since the acquisition of control in IVI in the third quarter of 2020, and the finalization of underutilized take or pay contracts for the Monterrey - El Porvenir pipeline, and for the Monterrey and Santiago offloading facilities.

Sales

($M)	Three months ended June 30 2021	Three months ended June 30 2020	Six months ended June 30 2021	Six months ended June 30 2020
Oil & gas sales, net of purchases [1]	200,581	81,701	381,537	324,536
Realized (loss) gain on risk management contracts	(24,877)	39,885	(35,857)	55,375
Royalties	(1,640)	—	(7,750)	(6,900)
Diluent costs	(803)	(8,273)	(7,417)	(15,741)
Net sales	**173,261**	**113,313**	**330,513**	**357,270**
$/boe using sales volumes from D&P assets	55.75	34.62	53.14	39.20

1. "Oil & gas sales, net of purchases" is a non-IFRS measure and includes crude oil and 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 15.

Oil & gas sales, net of purchases increased by $118.9 million and $57.0 million for the three and six months ended June 30, 2021, respectively, compared to the same periods of 2020, mainly due to higher Brent benchmark prices and narrower sales price differential (refer to the “Realized and Reference Prices” section on page 6 for the further detail on changes in prices).

Net sales for the three and six months ended June 30, 2021, increased by $59.9 million and decreased by $26.8 million, respectively, compared with the same periods of 2020. The following table describes the various factors that impacted net sales:

($M)	Three months ended June 30 2021-2020	Six months ended June 30 2021-2020
Net sales for the period ended June 30, 2020	113,313	357,270
Increased due to 159% higher oil and gas price (YTD 72% higher)	129,523	234,656
Decrease due to lower volumes sold of 1,812 boe/d or 5% (YTD 15,722 boe/d or 31% lower)	(10,643)	(177,655)
Change to realized loss on risk management contracts	(64,762)	(91,232)
Decrease in diluent costs	7,470	8,324
Increase in royalties	(1,640)	(850)
Net sales for the period ended June 30, 2021	**173,261**	**330,513**

Oil and Gas Operating Costs

($M)	Three months ended June 30 2021	Three months ended June 30 2020	Six months ended June 30 2021	Six months ended June 30 2020
Production costs	39,212	34,984	77,725	107,194
Transportation costs	32,343	40,606	69,427	106,658
Diluent costs	803	8,273	7,417	15,741
Cost of purchases [1]	18,436	—	22,440	1,003
Inventory valuation	5,237	(9,735)	8,465	33,380
(Settlement) overlift	(2)	90	(2,661)	240
Total oil and gas operating costs	**96,029**	**74,218**	**182,813**	**264,216**

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

For the three months ended June 30, 2021, total oil and gas operating costs increased by 29% compared to the same period of 2020. For the six months ended June 30, 2020 decreased 31% compared to the same periods of 2020. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs increased by 12% for the three months ended June 30, 2021, compared with the same period of 2020, mainly due to additional well services executed in 2021. For the six months ended June 30, 2021, production cost decreased 27% compared with the same period of 2020, primarily due to the closure of Peru operations and, reductions in variable cost in Colombia as a result of lower production.
- Transportation costs decreased by 20% and 35% for the three and six months ended June 30, 2021, compared with the same periods 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 BIC Ancillary Agreements and the CLC Ancillary Agreements since March 2020, and accounting eliminations from the consolidation of Puerto Bahia since the acquisition of control in IVI in the third quarter of 2020.
- Diluent costs decreased by 90% and 53% for the three and six months ended June 30, 2021, compared with the same periods of 2020, mainly due to lower diluent requirements resulting by the reduction in heavy oil production, optimization of

dilution strategy of CPE-6 volumes moved to Puerto Bahia, and accounting eliminations from the consolidation of Puerto Bahia since the acquisition of control in IVI in the third quarter of 2020.

- Cost of purchases for the three and six months ended June 30, 2021, increased by $18.4 million and $22.4 million 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.
- (Settlement) overlift was not significant for the second quarter of 2021. For the six months ended June 30, 2021, decreased due to the settlement of an overlift balance during the first half of 2021.
- Inventory valuation for the second quarter of 2021, was $15.0 million higher compared with the same quarter of 2020 due to drawdown of inventory in Colombia and Peru during 2021. For the six months ended June 30, 2021 inventory valuation decreased by $24.9 million mainly due to the significant drawdown of inventory in Peru resulting from the volumes sold during 2020.

Costs Under Terminated Pipeline Contracts

For the three and six months ended June 30, 2021, the Company had $Nil of costs under terminated pipeline contracts. For the same periods of 2020, the Company recorded $8.4 million and $11.2 million of costs in relation to the BIC Ancillary Agreements and CLC Ancillary Agreements. For further information refer to Note 28 of the 2020 Annual Consolidated Financial Statements.

Royalties

	Three months ended June 30		Six months ended June 30	
($M)	**2021**	**2020**	**2021**	**2020**
Royalties Colombia	1,640	—	7,750	6,857
Royalties Peru	—	—	—	43
Royalties	**1,640**	**—**	**7,750**	**6,900**
$/boe using sales volumes from D&P assets	0.53	—	1.25	0.76

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three and six months ended June 30, 2021, royalties increased $1.6 million and $0.9 million, respectively, compared to the same periods of 2020 primarily due to the increase in WTI oil benchmark price, although royalties cash royalties of $8.9 million were recognized during the second quarter of 2021, this was partially offset by a reversal of previously recorded provision. Refer to the “Production Reconciled to Sales Volumes” section on page 5 for further details of royalties paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended June 30		Six months ended June 30	
($M)	**2021**	**2020**	**2021**	**2020**
Depletion, depreciation and amortization	40,455	58,250	73,091	146,270

For the three and six months ended June 30, 2021, depletion, depreciation and amortization expense (“**DD&A**”) decreased by 31% and 50%, respectively, compared to the same periods of 2020, mainly due to lower depletable base as a result of a reduction in abandonment cost estimates and lower capital expenditures from the second quarter 2020 until the first quarter 2021, as well as a decrease in production during the three and six months ended June 30, 2021.

Impairment, Exploration Expenses and Other

($M)	Three months ended June 30 2021	Three months ended June 30 2020	Six months ended June 30 2021	Six months ended June 30 2020
Impairment of:				
Properties plant and equipment	—	—	—	77,864
Intangible assets	—	—	—	54,881
Exploration and evaluation assets	—	715	—	17,839
Other	—	—	—	888
Total impairment	**—**	**715**	**—**	**151,472**
Exploration expenses	89	44	171	477
(Recovery) expense of asset retirement obligations	(1,111)	2,614	(6,849)	(9)
Impairment, exploration expenses and other	**(1,022)**	**3,373**	**(6,678)**	**151,940**

For the six months ended June 30, 2021, the impairment was $Nil as no indicators were identified. In the first quarter of 2020, the Company recorded an impairment charge of $151.5 million primarily as a result of lower forecasted oil prices which reduced the expected future cash flows of its CGUs. As a result of the impairment test, the carrying amounts of certain assets relating to the Colombia CGUs were reduced to their recoverable amounts. 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 6 of the Interim Condensed Consolidated Financial Statements for the three and six months ended June 30, 2020 and 2019. Subsequently, the Company partially reversed this impairment charge in the fourth quarter of 2020 primarily due to the increase in oil prices.

During the three and six months ended June 30, 2021, the Company recognized a recovery of $1.1 million and $6.8 million, respectively, compared to an expense of $2.6 million and a recovery of $9 in the same periods of 2020 relating to the asset retirement obligation. When a decrease in the asset retirement obligations exceeds the carrying amount of the related asset, or there is an increase in the asset retirement obligations related to fully impaired or relinquished assets, the change is recognized as a recovery or expense of asset retirement obligations.

Other Operating Costs

($M)	Three months ended June 30 2021	Three months ended June 30 2020	Six months ended June 30 2021	Six months ended June 30 2020
General and administrative	14,132	9,716	27,334	24,731
Share-based compensation	3,142	1,316	4,459	2,533
Restructuring, severance and other costs	1,535	6,302	1,916	12,710

General and Administrative

For the three and six months ended June 30, 2021, G&A expenses increased 45% and 11% compared with the same periods of 2020, mainly due to the consolidation of Puerto Bahia since the acquisition of control in IVI in the third quarter of 2020, additional professional fees related to the Conciliation Agreement and CGX, and higher personnel expenses during 2021.

Share-based Compensation

For the three and six months ended June 30, 2021, share-based compensation increase to $3.1 million and $4.5 million, respectively, from $1.3 million and $2.5 million compared to the same periods of 2020. Share-based compensation reflects 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 CGX.

Restructuring, Severance and Other Costs

For the three and six months ended June 30, 2021, restructuring, severance and other costs decreased by $4.8 million and $10.8 million, respectively, compared with the same periods of 2020, primarily due to higher severance charges during the first half of 2020 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 June 30		Six months ended June 30	
	2021	2020	2021	2020
Finance income	3,675	6,167	4,515	10,845
Finance expenses	(13,747)	(11,728)	(27,334)	(26,988)
Foreign exchange loss	(48)	(2,535)	(18,536)	(23,132)
Other loss, net	(3,182)	(2,668)	(12,783)	(5,659)

Finance Income

For the three and six months ended June 30, 2021, finance income decreased by $2.5 million and $6.3 million, respectively, 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 June 30, 2021, finance expense increased by $2.0 million mainly due to the interest expense of borrowings consolidated from the acquisition of control in IVI. For the six months ended June 30, 2021, finances expense increases by $0.3 million mainly due to the interest expense from borrowings consolidated from the acquisition of control in IVI partially offset by, the discount to present value of dividends declared by Oleoducto Bicentenario de Colombia S.A.S. ("Bicentenario") during the first half of 2020 and, lower interest on lease liabilities.

Foreign Exchange Loss

For the three and six months ended June 30, 2021, foreign exchange loss was $48 thousand and $18.5 million, respectively, mainly due to the translation of the debt consolidated from IVI during 2020 and the Company's net working capital balances denominated in COP, compared with a loss of $2.5 million and $23.1 million in the same periods of 2020, primarily due to the impact of the COP´s depreciation against the USD on the translation of the Company's net working capital balances denominated in COP.

Other Loss, net

For the three and six months ended June 30, 2021, the Company recognized other losses of $3.2 million and $12.8 million, respectively, compared to other losses of $2.7 million and $5.7 million in the same periods 2020. The increase during the first half of 2021 was related mainly to the recognition of legal claims relating to the reassessment of contingencies from the allegedly late delivery of production from the Quifa block prior to 2014 (for further information refer to Note 15 of the Interim Financial Statements).

(Loss) Gain on Risk Management Contracts

($M)	Three months ended June 30		Six months ended June 30	
	2021	2020	2021	2020
Realized (loss) gain on risk management contracts(1)	(24,877)	12,589	(35,857)	28,079
Realized gain on unwinding of risk management contracts(1)	—	27,296	—	27,296
Unrealized gain (loss) on risk management contracts(2)	7,453	(36,011)	(1,385)	(6,871)
Total (loss) gain on risk management contracts	**(17,424)**	**3,874**	**(37,242)**	**48,504**

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 and six months ended June 30, 2021, the realized loss on risk management contracts was $24.9 million and $35.9 million, compared to a gain of $12.6 million and $28.1 million in the same period of 2020, primarily from the cash settlement on 3-ways and Put Spreads contracts paid during the three and six months ended June 30, 2021 at an average price of $69.01/bbl.

During the second quarter of 2020, the realized gain on risk management contracts included $27.3 million from the unwinding and early termination of contract positions for the remainder of 2020 which were fully in-the-money. A portion of the proceeds were redeployed to provide additional downside Brent benchmark price protection for the second half of 2020 and first half of 2021.

The unrealized gain on risk management contracts for the three months ended June 30, 2021, was $7.5 million compared to a $36.0 million loss in the same period of the previous year, due to the primarily related to the reclassification of amounts to realized gain or loss from instruments settled during the period. For the six months ended June 30, 2021, the unrealized loss was lower than the same period of the previous year, due to the increased in the benchmark forward prices of Brent oil.

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% 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. In 2021, the Company executed a risk management strategy using a variety of derivatives instruments, including 3 - ways, puts and put spreads 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 $**	**Assets**	**Liabilities**
3-ways	July to December 2021	Brent	360,000	37.0/47.0/62.9	—	3,951
Put Spread	July to December 2021	Brent	2,514,000	39.4/49.4	520	—
Put	July to October 2021	Brent	953,000	60.0	487	—
Total as at June 30, 2021					**1,007**	**3,951**

Subsequent to June 30, 2021, the Company continued with its hedging program increasing its hedged production from 40% to 60% for the remainder of 2021, using $60 puts, as follows:

				Avg. Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $**
Put	November to December 2021	Brent	454,000	60.0

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 June 30, 2021, the Company has entered into new positions of foreign currency derivatives contracts, detailed as follows:

					Carrying Amount	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume USD ($M)**	**Put/ Call; Par forward (COP$)**	**Assets**	**Liabilities**
Zero-cost collars	July to December 2021	COP / USD	$ 120,000	3,500 / 4,120	—	471
Total as at June 30, 2021					**—**	**471**

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

As part of the acquisition of control in IVI, the Company consolidated a financial derivative to manage exposure to cash flow risks from the fluctuation of the interest rate expressed in LIBOR on the 2025 Puerto Bahia Debt. Refer to "Liquidity and Capital Resources" section on page 17 for further information. As at June 30, 2021, the Company had the following interest rate swap contract outstanding:

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount $M**	**Floating rate**	**Assets**	**Liabilities**
Swap	July 2021 to June 2025	LIBOR + 180	121,100	3.9%	—	9,399
Total as at June 30, 2021					**—**	**9,399**

Income Tax Expense

	Three months ended June 30		Six months ended June 30	
($M)	**2021**	**2020**	**2021**	**2020**
Current income tax expense	(20,025)	(1,161)	(24,216)	(6,256)
Deferred income tax expense	(17,844)	—	(26,933)	(167,979)
Total income tax expense	**(37,869)**	**(1,161)**	**(51,149)**	**(174,235)**

Current income tax expense for the second quarter of 2021 was $20.0 million, compared with $1.2 million in the same quarter of 2020. The increase is mainly due to a provision recognized of $20.9 million, related to changes in prior year tax assessments.

Deferred income tax expense for the second quarter of 2021 was $17.8 million compared with $Nil mainly from the Company recognized an income tax expense of $17.5 million related to deferred tax asset utilization.

For the six months ended June 30, 2021 the current income tax expense was $24.2 million, compared with $6.3 million in the same period of 2020. The increase is mainly due to a provision of $20.9 million, related to changes in prior year tax assessments. Deferred income tax expense for the six months ended June 30, 2021 was $26.9 million compared with $168.0 million in the same period of 2020. The 2021 expense is related to the utilization of the deferred tax asset, while the expense for 2020 is related to the derecognition of deferred tax assets in Colombia driven by the reduction in global crude oil prices.

Net Loss

	Three months ended June 30		Six months ended June 30	
($M)	**2021**	**2020**	**2021**	**2020**
Net loss attributable to equity holders of the Company	(25,648)	(67,760)	(39,774)	(455,569)
Per share – basic ($)	(0.26)	(0.70)	(0.41)	(4.72)
Per share – diluted ($)	(0.26)	(0.70)	(0.41)	(4.72)

The Company reported a net loss of $25.6 million for the second quarter of 2021 which included a Debt extinguishment costs of $29.1 million, total income tax expense of $37.9 million, a loss on risk management contracts of $17.4 million partially offset by $65.6 million of operating income. This compared to a net loss of $67.8 million in the second quarter of 2020, which included a loss from operations of $79.9 million driven by lower oil price realizations.

For the six months ended June 30, 2021 the Company reported a net loss of $39.8 million which included a loss on risk management contracts of $37.2 million, a Debt extinguishment costs of $29.1 million, total income tax expense of $51.1 million, partially offset by, $117.2 million of operating income. This compared to a net loss of $455.6 million in the in the same period 2020, which included a loss from operations of $295.0 million (including a non-cash impairment charge of $151.9 million), and deferred income tax expense of $168.0 million.

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
($M)	**2021**	**2020**	**2021**	**2020**
Development capital	37,224	10,002	45,319	57,796
Exploration activities [1]	21,971	5,220	27,653	21,990
Infrastructure and other capital	2,019	429	2,607	541
Total capital expenditures	**61,214**	**15,651**	**75,579**	**80,327**

1. Includes expenditures, net of income from E&E assets.

Capital expenditures for the three and six months ended June 30, 2021, were $61.2 million and $75.6 million, respectively, which were $45.6 million higher and $4.7 million lower than the same periods of 2020, the variance in capital expenditures was mainly due to the following:

- During the three and six months ended June 30, 2021, development capital increased by $27.2 million and decreased by $12.5 million respectively, compared to the same periods of 2020, mainly due to a total of 12 development wells drilled in CPE6, Quifa and La Creciente blocks. During the same periods of 2020, the Company drilled a total of 3 and 21 development wells, respectively, in Quifa, CPE6, Canaguaro and Sabanero blocks.
- For the three and six months ended June 30, 2021, exploration activities increased by $16.8 million and $5.7 million mainly as a result of exploration activities in Guyana. The Company, through its majority-owned subsidiary and joint venture partner CGX, continues its preparation activities to spud Kawa-1 exploration well in the Corentyne block that is expected to occur between August 20 and 24 of 2021. Also after preparation activities on the VIM-I in Colombia the Basilea-1 well was drilled in July, but mechanical difficulties prevented the well from reaching the target zone, the well has been temporarily suspended while forward plans are being evaluated. During the three and six months ended June 30, 2020 Nil and one exploration well was drilled respectively.
- During the three and six months ended June 30, 2021, infrastructure and other capital increased by $1.6 million and $2.1 million, mainly due to works related to the construction of the Berbice Deep Water Port in Guyana.

Selected Quarterly Information

Operational and financial results		2021 Q2	2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1	2019 Q4	2019 Q3
Heavy crude oil production	(bbl/d)	17,241	20,997	21,074	21,997	22,533	31,996	32,586	33,906
Light and medium crude oil production	(bbl/d)	17,535	18,685	19,756	19,820	18,415	29,539	36,095	34,024
Total crude oil production	(bbl/d)	34,776	39,682	40,830	41,817	40,948	61,535	68,681	67,930
Conventional natural gas production	(mcf/d)	5,164	5,227	6,356	7,895	9,399	11,611	12,677	13,013
Total production	(boe/d)	35,682	40,599	41,945	43,202	42,597	63,572	70,905	70,213
Sales volumes, net of purchases (D&P) - (boe)[(1)]	(boe/d)	34,151	34,555	44,551	39,966	35,963	34,186	65,646	54,163
Brent price	($/bbl)	69.08	61.32	45.26	43.34	33.39	50.82	62.42	62.03
Oil & gas sales, net of purchases [(1)]	($/boe)	64.54	58.18	42.20	40.18	24.96	41.57	58.56	56.65
Realized (loss) gain on risk management contracts	($/boe)	(8.00)	(3.53)	(2.00)	(1.70)	12.19	2.65	(0.66)	(0.43)
Royalties	($/boe)	(0.53)	(1.96)	(0.47)	(0.23)	—	(1.18)	(0.98)	(2.42)
Diluent costs	($/boe)	(0.26)	(2.13)	(1.75)	(1.52)	(2.53)	(1.28)	(0.55)	(0.38)
Net sales realized price	($/boe)	55.75	50.56	37.98	36.73	34.62	41.76	56.37	53.42
Production costs	($/boe)	(12.08)	(10.54)	(13.46)	(8.97)	(9.03)	(12.48)	(13.76)	(11.60)
Transportation costs	($/boe)	(10.84)	(10.89)	(10.93)	(9.89)	(11.28)	(12.44)	(12.84)	(12.00)
Operating netback	($/boe)	32.83	29.13	13.59	17.87	14.31	16.84	29.77	29.82
Revenue	($M)	224,685	184,734	177,109	152,760	81,701	236,938	351,027	277,676
Net (loss) income	($M)	(25,648)	(14,126)	48,636	(90,473)	(67,760)	(387,809)	69,408	(49,117)
Per share – basic ($)	($)	(0.26)	(0.14)	0.50	(0.93)	(0.70)	(4.04)	0.71	(0.50)
Per share – diluted ($)	($)	(0.26)	(0.14)	0.48	(0.93)	(0.70)	(4.04)	0.70	(0.50)
General and administrative	($M)	14,132	13,202	19,851	10,539	9,716	15,015	22,897	18,476
Operating EBITDA	($M)	84,771	69,158	35,639	52,113	37,608	46,982	137,052	124,586
Capital expenditures	($M)	61,214	14,365	24,871	2,905	15,651	64,676	132,452	70,761

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 “Non-IFRS Measures” section on page 15 for further details.

Over the past eight quarters, the Company’s sales have fluctuated due to changes in production, timing of cargo shipments, movement in Brent benchmark prices, and fluctuations in crude oil price differentials. In addition to decreases in the Company’s production since 2019 due to natural declines on its mature fields, during the past four quarters there was a significant reduction in production resulting from the voluntary shut-in of production from certain blocks during the second and third quarters of 2020 due to the low global crude oil price environment and the impact of the COVID-19 pandemic, significant reduction of capital spending, the cessation of production in Peru since March 2020 and the reduction in transportation cost since early 2020 due to the cessation of payments for unused facilities under the BIC Ancillary Agreements and CLC Ancillary Agreements. For further information refer to Note 28 of the 2020 Annual Consolidated Financial Statements.

Trends in the Company’s net (loss) income are also impacted most significantly by the recognition and derecognition of deferred income taxes, DD&A, Debt extinguishment costs , impairment charges of oil, gas and other assets, reclassification of currency translation adjustment on the acquisition of control in IVI, recognition of contingency provision from the Conciliation Agreement (refer to “Conciliation Agreement” section on page 21 for further details), 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.

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. The midstream segment principally includes the following assets:

Project [1]	Description	Interest	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	94.16% interest in Puerto Bahía	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	59.93% interest in PIL (which holds a 35% interest in the ODL Pipeline)	Equity Method [2]
Bicentenario Pipeline ("**BIC Pipeline**")	Crude oil pipeline, capacity of 120,000 bbl/day	43.03% equity interest in Bicentenario	Equity Method [2][3]

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. Equity method accounting requires that the carrying value of the investment be increased to reflect the Company's proportionate share of net income, or reduced to reflect its share of net losses and dividends declared.
3. As a result of the reclassification of the Bicentenario investment to asset held for sale, the equity method was stopped in the fourth quarter of 2020.

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 from 39.22% to 71.57% and as a result, began to consolidate Puerto Bahia. On December 30, 2020, the Company further increased its ownership to 94.16% through the conversion of certain debt into preferred shares with voting rights.

For the six months ended June 30, 2021 Puerto Bahia has generated $21.0 million of segment operating income primarily from take-or-pay contracts in its liquid bulk storage terminal business. For the six months ended June 30, 2020, prior to the acquisition of a controlling interest in Puerto Bahia on August 6, 2020, the Company had recognized $18.5 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 Oleoducto de los Llanos Orientales ("**ODL")**. ODL owns the Oleoducto de los Llanos pipeline, which connects the Rubiales, Quifa and Llanos-34 b to the Monterrey Station or Cusiana Station in the Casanare Department.

For the six months ended June 30, 2021, the Company recognized $19.6 million as its share of income from ODL which was $2.7 million lower than the same period of 2020 primarily due decrease in the transportation tariff since the second quarter 2020 and impact of foreign exchange fluctuations. During the six months ended June 30, 2021, the Company recognized gross dividends of $41.6 million and a return of capital of $4.2 million. As at June 30, 2021, the Company has accounts receivables of $19.6 million of dividends and return of capital contributions.

Bicentenario Pipeline

The Company holds a 43.03% interest in Bicentenario, which owns the BIC Pipeline that connects the Araguaney Station in the Casanare Department to the Banadia Station in the Arauca Department. At the Banadia Station, the BIC Pipeline connects to the Caño Limon Coveñas pipeline ("**CLC Pipeline**"), which connects to the Coveñas terminal on Colombia's Caribbean coastline in the Sucre Department. On November 16, 2020, the Company, Bicentenario and Cenit Transporte y Logística de Hidrocarburos S.A.S. ("**Cenit**") signed a Conciliation Agreement, which includes a full and final mutual release upon closing of all present and future amounts claimed by all parties in respect of terminated transportation and other contracts for both the CLC Pipeline and the BIC Pipeline. Refer to the "Conciliation Agreement Update" section on page 21 for further details.

As at June 30, 2021, the Company has recorded a carrying value of dividends receivable from Bicentenario of $56.6 million and the balance of the investment in Bicentenario of $60.5 million recognized as assets held for sale.

Midstream Segment Results

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

	Three months ended June 30		Six months ended June 30	
($M)	**2021**	**2020**	**2021**	**2020**
Revenue	18,429	—	35,274	—
Costs	(4,787)	—	(9,315)	—
General and administrative	(1,819)	(167)	(3,295)	(249)
Depletion, depreciation and amortization	(913)	—	(1,706)	—
Segment income (loss) from operations	**10,910**	**(167)**	**20,958**	**(249)**
Share of Income from associates - ODL	9,805	10,133	19,591	22,294
Share of Income from associates - Bicentenario	—	6,623	—	11,135
Share of income (loss) from associates - IVI	—	6,580	—	(18,499)
Segment income	**20,715**	**23,169**	**40,549**	**14,681**

Non-IFRS Measures

This MD&A contains the following terms that do not have standardized definitions in IFRS: "operating EBITDA," "Oil & 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 on page 19). Refer to the "Liquidity and Capital Resources – Covenants" section on page 17.

The Company's determination of these non-IFRS measures may differ from other reporting issuers and 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 (loss) income 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 loss to operating EBITDA:

	Three months ended June 30		Six months ended June 30	
($M)	**2021**	**2020**	**2021**	**2020**
Net loss	(25,648)	(67,760)	(39,774)	(455,569)
Finance income	(3,675)	(6,167)	(4,515)	(10,845)
Finance expenses	13,747	11,728	27,334	26,988
Income tax expense	37,869	1,161	51,149	174,235
Depletion, depreciation and amortization	40,455	58,250	73,091	146,270
Impairment and others	(1,111)	3,329	(6,849)	151,463
Costs under terminated pipeline contracts	—	8,391	—	11,230
Share-based compensation	3,142	1,316	4,459	2,533
Restructuring, severance and other costs	1,535	6,302	1,916	12,710
Share of income from associates	(9,805)	(23,336)	(19,591)	(14,930)
Foreign exchange loss	48	2,535	18,536	23,132
Unrealized (gain) loss on risk management contracts	(7,453)	36,011	1,385	6,871
Other loss, net	3,182	2,668	12,783	5,659
Non-controlling interests	3,373	3,180	4,893	4,843
Debt extinguishment costs	29,112	—	29,112	—
Operating EBITDA	**84,771**	**37,608**	**153,929**	**84,590**

Net Sales

Net sales is 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 diluent 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 diluent, the cost of which is partially recovered when the blended product is sold. Net sales also excludes sales from port services, as it is not considered part of the oil & gas segment. Refer to the reconciliation in the "Sales" section on page 7.

Operating Netback

Operating netback is used to assess the net margin of the Company's production after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel and is an indicator of how efficient the Company is at extracting and selling its product. For netback purposes, the Company removes the effects of any trading activities and results from its Midstream segment from the per barrel metrics. Refer to the reconciliation in the "Operating Netback" section on page 6.

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

Oil & 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 June 30		Six months ended June 30	
	2021	**2020**	**2021**	**2020**
Oil and gas sales ($M) (1)	219,017	81,701	403,977	325,539
(-) Cost of purchases ($M) (2)	(18,436)	—	(22,440)	(1,003)
Oil & gas sales, net of purchases ($M)	**200,581**	**81,701**	**381,537**	**324,536**
Sales volumes, net of purchases (D&P) - (boe)	3,107,729	3,272,633	6,217,712	9,113,468
Oil & gas sales, net of purchases ($/boe)	64.54	24.96	61.35	35.61

1. Excludes sales from port services as they are not part of the oil & gas segment. For further information, refer to the "Midstream Activities" section on page 14.
2. Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining costs.

Net sales realized price per boe is calculated using net sales (including oil and gas sales net of purchases, realized gains and losses from risk management contracts less royalties and diluent costs) divided by the total sales volumes, net of purchases from D&P assets. A reconciliation of this calculation is provided below:

	Three months ended June 30		Six months ended June 30	
	2021	**2020**	**2021**	**2020**
Net sales ($M)	173,261	113,313	330,513	357,270
Sales volumes, net of purchases (D&P) - (boe)	3,107,729	3,272,633	6,217,712	9,113,468
Net sales realized price ($/boe)	55.75	34.62	53.14	39.19

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 June 30		Six months ended June 30	
	2021	**2020**	**2021**	**2020**
Production costs ($M)	39,212	34,984	77,725	107,194
Production (boe)	3,247,062	3,876,332	6,900,806	9,661,652
Production costs ($/boe)	12.08	9.03	11.26	11.09

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 June 30		Six months ended June 30	
	2021	**2020**	**2021**	**2020**
Transportation costs ($M)	32,343	40,606	69,427	106,658
Net production (boe)	2,982,798	3,598,950	6,388,033	8,907,262
Transportation costs ($/boe)	10.84	11.28	10.87	11.97

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 (2025 Puerto Bahia Debt) and certain amounts attributable to the Unrestricted Subsidiaries.

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

	As at June 30
($M)	**2021**
2023 senior note balance(1)	63,401
Long-term debt	391,006
Total lease liabilities (2)	10,602
Risk management liabilities, net(3)	3,415
Consolidated Total Indebtedness excluding 2025 Puerto Bahia Debt	468,424
(-) Cash and Cash Equivalents (4)	(329,723)
(=) Net Debt excluding 2025 Puerto Bahia Debt	138,701

1. Including as *Accounts payable and accrued liabilities* in the Interim Financial Statements
2. Excludes $0.5 million of lease liabilities attributable to the Unrestricted Subsidiaries.
3. Excludes $9.4 million of risk management liabilities attributable to the Unrestricted Subsidiaries.
4. Excludes $28.6 million of cash and cash equivalents attributable to the Unrestricted Subsidiaries.

4. LIQUIDITY AND CAPITAL RESOURCES

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

- capital expenditures for exploration, production and development, including growth plans;
- costs and expenses relating to operations, commitments and existing contingencies;
- debt service requirements relating to existing and future debt; and
- enhancing shareholders 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 at June 30, 2021, the Company had a total cash balance of $486.6 million (including $128.3 million in restricted cash and $63.4 million in cash that were utilized to repay the remaining balance of the 2023 Unsecured Notes on July 7, 2021), which is $85.4 million higher than at December 31, 2020. For the six months ended June 30, 2021, the Company generated $134.8 million in operating cash flows which was used to fund cash outflows of $26.2 million for capital expenditures and other investing activities. For the six months ended June 30, 2021, financing activities generates net inflows of $22.0 million as a result of a net cash inflow of $397.4 million ($400 million issuance minus $2.6 million of issue price) from the 2028 Unsecured Notes partially offset by the repayment of $286.6 million of the Unsecured Notes 2023, $22.8 million of interest and other financing charges, $20.0 million of 2025 Puerto Bahia Debt payments, $9.3 million common shares repurchased, $8.3 million in lease payments and, $8.1 million of dividends paid to equity holders. As a result, the working capital deficit reduced to $23.9 million compared with $111.7 million at year-end.

Since the third quarter of 2020, the Company's consolidated working capital position was reduced to a deficit due to the acquisition of control in IVI, which resulted in the consolidation of the 2025 Puerto Bahia Debt ($163.1 million as June 30, 2021) classified as a current liability (for further information of the 2025 Puerto Bahia Debt refer to "Puerto Bahia Secured Syndicated Credit Loan" section on page 19 and Note 20 of the 2020 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 June 30, 2021, the main components of restricted cash were long-term abandonment funds as required by the ANH, cash collateral required for certain legal proceedings, 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. Cash collateral for legal processes is expected to be released as the related processes are closed. As of June 30, 2021, total restricted cash of $128.3 million, decreased by $40.7 million from December 31, 2020, primarily due to the release of $10.0 million of abandonment funds that were replaced with letters of credit, the release of $12.5 million exploration commitments due to the reduction in cash collateral requirements under new letters of credit lines, the release of $11.0 million due to a new agreement with Citibank regarding cash collateral of letters of credit and foreign exchange fluctuations.

The measures taken by the Company to manage its liquidity and capital resources are ongoing and the Company continues to look for additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of such measures, the Company expects that unrestricted cash balances in conjunction with future cash flows from operations, available credit facilities, and alternate financing arrangements, will be sufficient to support its working capital deficit, operational and capital requirements and other financial commitments. The Company 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 22.

Unsecured Notes

The Company’s long-term borrowing consists of 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 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 2023 Unsecured Notes, which were set to mature in 2023. The remaining proceeds will be used for general corporate purposes.

Frontera 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 Redemption Notes, plus (ii) accrued and unpaid interest, if any, through the Redemption Date, plus (iii) any other amounts accrued and unpaid thereon under the terms of the 2023 Unsecured Notes and the Indenture, including Additional Amounts, if any. The Company’s long-term borrowing of $350.0 million of 2023 Unsecured Notes was completely discharged on July 7, 2021.

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

Puerto Bahia Secured Syndicated Credit Loan

During the third quarter of 2020, the Company acquired control of IVI which holds 99.9% of Puerto Bahia (for further information refer to Note 20 of the 2020 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, which is secured by substantially all the assets and shares of Puerto Bahia, and which is non recourse to the Company (other than as provided for by the equity contribution agreement (“**ECA**”) described below), and it has no impact on the Company’s financial covenants under the 2028 Unsecured Notes. As at June 30, 2021, the 2025 Puerto Bahia Debt outstanding amount is $163.1 million.

As part of the agreements for the bank loan to fund the construction of Puerto Bahia, the Company entered into the ECA signed 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 $85.3 million under the ECA Loans, of which $41.3 million was capitalized into preferred shares of Puerto Bahia during the fourth quarter of 2020 (refer to the “Midstream Activities” section on page 14 for further details). As a result of the acquisition of control in IVI, all intercompany balances and transactions between the Company and IVI are eliminated on consolidation.

Letters of Credit

The Company has various uncommitted bilateral letters of credit lines. As of June 30, 2021, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $72.7 million, with cash collateral of $14.3 million. During July 2021, the Company increased the credit line with Banco BTG Pactual S.A. by an additional amount of $15 million, these new uncommitted credit line do not require cash collateral as a result Frontera released $9.1 million of restricted cash amounts.

Unsecured Notes Covenants

The 2028 Unsecured Notes are senior, unsecured 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 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 U.S.$56.1 million. The 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 June 30, 2021, the Company is in compliance with all such covenants.

As of June 30, 2021, and pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $468,424,000 consolidated adjusted EBITDA of $254,492,000 and consolidated interest expense of $32,348,000.

1. Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the indenture governing the Unsecured Notes (the "**Indenture**") as the consolidated total indebtedness as of such date divided by consolidated adjusted EBITDA for the most recently ended period of four consecutive fiscal quarters.
    a. Consolidated total indebtedness is defined under "Non-IFRS Measures" on page 15.
    b. Consolidated adjusted EBITDA is defined as the consolidated net income (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 ended period 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.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at June 30, 2021, undiscounted by calendar year, are presented below:

As at June 30, 2021 ($M)	2021	2022	2023	2024	2025	2026 and Beyond	Total
Financial obligations							
Long-term debt, including interest payments	15,750	31,500	31,500	31,500	31,500	478,750	620,500
Lease liabilities	3,508	5,630	3,097	94	56	—	12,385
2025 Puerto Bahía Debt and interest (1)	24,271	47,126	49,982	47,651	13,591	—	182,621
Total financial obligations	**43,529**	**84,256**	**84,579**	**79,245**	**45,147**	**478,750**	**815,506**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	$ 34,808	$ 69,616	$ 69,616	$ 69,616	$ 35,060	$ —	$ 278,716
Other transportation agreements	3,782	—	—	—	—	—	3,782
Exploration commitments							
Minimum work commitments (2)	77,761	75,385	41,691	43,965	—	—	238,802
Other commitments							
Operating purchases, leases and community obligations	6,433	9,675	9,225	13,522	2,516	1,322	42,693
Total Commitments	**122,784**	**154,676**	**120,532**	**127,103**	**37,576**	**1,322**	**563,993**

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 June 30, 2021, the Company, through its 73.85% interest in CGX, has exploration work commitments under its Petroleum Prospecting Licenses (“**PPL**”) for blocks in Guyana, as follows:

- In accordance with the Corentyne PPL, which is currently in phase one of the second renewal period, one (1) exploration well must be drilled by November 27, 2021.
- In accordance with the Demerara PPL, which is currently in phase one of the second renewal period, one (1) exploration well must be drilled by February 11, 2022.
- In accordance with the Berbice PPL, which is currently in phase one of the second renewal period until August 11, 2022, the Company shall complete a seismic program, including all associated processing and interpretations, so as to inform and lead to the drilling of at least one (1) exploratory well by June 15, 2022.

The Company, through its interest in CGX, has entered into agreements for activities to complete its requirement under the Corentyne and Demerara contracts, and for the port. As at June 30, 2021, aggregate minimum future obligation still outstanding under these agreements is $68.1 million expected to be paid in 2021. These activities include an agreement with a third party to complete drilling activities in 2021 on the Corentyne block. Under the agreement, the Company has provided a parent guarantee in the event of non-performance by CGX for certain obligations up to a maximum of $25.0 million.

Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company’s favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company’s financial position, results of operations or cash flows.

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 June 4, 2021, the Company filed a request to transfer the outstanding commitments, however, on July 30, 2021, the ANH rejected the Company's proposal and demanded payment for unfulfilled commitments. Currently, the Company is assessing the next actions against the ANH’s decision. The Company has a total of $13.1 million of letters of credit as guarantee for the contracts in favor of the ANH. As of June 30, 2021, the Company has not recognized any provision for this ANH discussion since it considers that the probability of an unfavorable result is less than probable.

Conciliation Agreement

On November 16, 2020, the Company, Cenit and Bicentenario reached an agreement (the “**Conciliation Agreement**”) for the joint filing of a petition for binding settlement which, upon completion and approval by Administrative Tribunal of Cundinamarca (the "**Court**"), will resolve all the disputes between the parties related to the BIC Pipeline and the CLC Pipeline, and will terminate all the pending arbitration proceedings related to such disputes, including the Bicentenario Arbitration, CLC Arbitration and International Arbitration. For further information refer to Note 28 of the 2020 Annual Consolidated Financial Statements.

On March 24, 2021, the Company announced that the Office of the Procuraduría General de la Nación has delivered its opinion on the Conciliation Agreement. The opinion is favorable, recommending that the conciliation be approved. The terms of the Conciliation Agreement remain the same as previously disclosed.

Delivery of the favorable opinion by the Procuraduría General de la Nación represents the first of two stages of review of the Conciliation Agreement. If the Conciliation Agreement is approved by Court, the second stage of the process will be completed, and the parties will be able to complete the settlement arrangement. There can be no assurance that Court approval will be received on a timely basis or at all.

Given the favorable opinion delivered by the Procuraduría General de la Nación, recommending that the Conciliation Agreement be approved, the Company, Cenit and Bicentenario agreed to extend the deadline for the approval of the Conciliation Agreement to September 30, 2021 or such later date as may be further agreed. If the Conciliation Agreement is not approved by September 30, 2021, then either party will become entitled to terminate the settlement arrangement, and the legal rights of the parties with respect to the disputes will not be prejudiced unless and until the required approval is obtained and the settlement arrangement is closed.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at August 9, 2021:

	Number
Common shares	96,313,979
Deferred share units ("**DSUs**") (1)	701,875
Restricted share units ("**RSUs**") (2)	2,191,893

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

During the first quarter of 2020, the Company suspended its quarterly dividend due to the oil price decline. Prior to the suspension, the Company had 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 twelve-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). 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. ("**BMO**"), on behalf of Frontera in accordance with the plan and applicable regulatory requirements. During the three and six months ended June 30, 2021, the Company purchased 1,525,500 and 1,787,500 Common Shares, respectively, under the new NCIB. As at August 9, 2021, the Company had repurchased for cancellation a total of 2,225,500 Common Shares for $11.8 million with an additional 2,972,112 Common Shares available for repurchase under the NCIB.

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

	Six months ended June 30 2021
Number of common shares repurchased	1,787,500
Total amount of common shares repurchased ($M)	9,283
Weighted-average price per share ($)	5.19

6. RELATED-PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances outstanding and commitments with related parties, as at June 30, 2021 and December 31, 2020, and for the three and six months ended June 30, 2021 and 2020, respectively:

($M)		Accounts Receivable (1)	Accounts Payable	Commitments	Cash Advance (1)
ODL	2021	19,893	5,415	—	—
	2020	465	7,821	7,888	—
Bicentenario	2021	68,005	—	—	87,278
	2020	70,761	—	—	87,278

		Three months ended June 30		Six Months Ended June 30	
($M)		Purchases / Services	Interest Income (1)	Purchases / Services	Interest Income (1)
ODL	2021	7,281	—	16,353	—
	2020	8,467	—	20,429	—
Bicentenario	2021	—	—	—	—
	2020	—	—	1,267	—
IVI (2)	2021	—	—	—	—
	2020	9,247	4,514	19,065	9,025

1. Amounts presented based on contractual payment obligations undiscounted and prior to impairments.
2. 2020 balances shown reflect transactions before the Company acquired control of IVI on August 6, 2020.

7. RISKS AND UNCERTAINTIES

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

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

For a comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the AIF and 2020 Annual Consolidated Financial Statements as of December 31, 2020, copies of which are available on SEDAR at www.sedar.com.

In addition, the COVID-19 pandemic has 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 result in continued fluctuations in the price of oil and natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events 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 17 for additional detail on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

8. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Interim Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook - Accounting. A summary of significant accounting policies applied is included in Note 3a of the 2020 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 2020 Annual Consolidated Financial Statements, including management's evaluation of impact and implementation progress.

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

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

The effect of the 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 now. There may also be effects that are not currently known, as the full impact and duration of the COVID-19 pandemic is still uncertain. As a result, it is difficult to reliably assess the full impact this will have on the Company's business, financial conditions and results of operations which presents uncertainties and risks in management's judgments, estimates, and assumptions used in the preparation of the Interim Financial Statements.

The results of the economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's judgments and estimates as described above for the quarter end; however, there could be further prospective material impacts in future periods. As such, actual results may differ from these estimates under different assumptions or conditions. A summary of the significant judgments and estimates made by management in the preparation of its financial information is provided in Note 3c of 2020 Annual Consolidated Financial Statements.

9. INTERNAL CONTROL

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

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations.

There have been no changes in the Company's ICFR during the quarter ended June 30, 2021, that have materially affected, or are reasonably likely to materially affect, its ICFR.

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

10. FURTHER DISCLOSURES

Production Reporting

Production volumes are reported on a Company 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 in 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		**Q2 2021**	**Q1 2021**	**Q2 2020**	**YTD 2021**	**YTD 2020**
Heavy oil	(bbl/d)	15,802	19,632	20,781	17,706	25,066
Light and medium oil	(bbl/d)	16,070	17,288	17,119	16,676	19,784
Conventional natural gas production	(mcf/d)	5,164	5,227	9,399	5,193	10,505
Net production Colombia	**(boe/d)**	**32,778**	**37,837**	**39,549**	**35,293**	**46,693**
Producing blocks in Peru						
Light and medium oil	(bbl/d)	—	—	—	—	2,248
Net production Peru (1)	**(bbl/d)**	**—**	**—**	**—**	**—**	**2,248**
Total net production	**(boe/d)**	**32,778**	**37,837**	**39,549**	**35,293**	**48,941**

1. No production in Peru after the first quarter 2020, due to on February 27, 2020, Block 192 was placed in force majeure as a result of a community blockade. Then, 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 8.

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**	Thousand cubic feet
bbl/d	Barrels of oil per day	**mcf/d**	Thousand cubic feet per day
boe	Barrels of oil equivalent	**PAP**	High-price clause participation
boe/d	Barrels of oil equivalent per day	**Q**	Quarter
COP	Colombian pesos	**USD**	United States dollars
C$	Canadian dollars	**WTI**	West Texas Intermediate
D&P	Development and producing	**$**	U.S. dollars
E&E	Exploration and evaluation	**$M**	Thousand U.S. dollars
MMbbl	Millions of oil barrels	**$MM**	Million U.S. dollars