MANAGEMENT DISCUSSION & ANALYSIS

November 2, 2021

For the three and nine months ended September 30, 2021

*Frontera Energy Corporation ("**Frontera**" or the "**Company**") is an oil and gas company formed and existing under the laws of British Columbia, Canada, that is engaged in the exploration, development and production of crude oil and conventional 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 nine months ended September 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 16.*

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 volatile 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 conventional natural gas products, production levels, cash levels, reserves, capital expenditures (including plans and projects related to drilling, exploration activities, and infrastructure and the timing thereof), operating EBITDA, production costs, transportation costs and the foreseeable impact of the Conciliation Agreement (as defined below) the event legal approvals are obtained, 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

					Nine months ended September 30	
		Q3 2021	Q2 2021	Q3 2020	2021	2020
Operational Results						
Heavy crude oil production	(bbl/d)	18,168	17,241	21,997	18,791	25,495
Light and medium crude oil production	(bbl/d)	17,371	17,535	19,820	17,859	22,581
Total crude oil production (1)	(bbl/d)	35,539	34,776	41,817	36,650	48,076
Conventional natural gas production (1)	(mcf/d)	5,033	5,164	7,895	5,141	9,627
Total production (2)(3)	(boe/d) (4)	36,422	35,682	43,202	37,552	49,765
Oil & gas sales, net of purchases (5)	($/boe)	67.13	64.54	40.18	63.00	36.92
Realized (loss) gain on risk management contracts	($/boe)	(2.68)	(8.00)	(1.70)	(4.89)	3.83
Royalties	($/boe)	(4.83)	(0.53)	(0.23)	(2.26)	(0.61)
Diluent costs	($/boe)	(0.15)	(0.34)	(1.62)	(0.97)	(1.76)
Net sales realized price (6)	($/boe)	59.47	55.67	36.63	54.88	38.38
Production costs (7)	($/boe)	(11.44)	(11.72)	(8.55)	(11.03)	(10.10)
Transportation costs (8)	($/boe)	(10.24)	(11.15)	(10.24)	(10.91)	(11.67)
Operating netback (9)	($/boe)	37.79	32.80	17.84	32.94	16.61
Financial Results						
Oil & gas sales, net of purchases	($M)	164,731	200,581	147,832	546,268	472,368
Realized (loss) gain on risk management contracts	($M)	(6,570)	(24,877)	(6,246)	(42,427)	49,129
Royalties	($M)	(11,848)	(1,640)	(861)	(19,598)	(7,761)
Diluent costs	($M)	(366)	(1,056)	(5,954)	(8,405)	(22,504)
Net sales (9)	($M)	145,947	173,008	134,771	475,838	491,232
Net income (loss) (10)	($M)	38,531	(25,648)	(90,473)	(1,243)	(546,042)
Per share – basic	($)	0.40	(0.26)	(0.93)	(0.01)	(5.64)
Per share – diluted	($)	0.39	(0.26)	(0.93)	(0.01)	(5.64)
General and administrative	($M)	12,656	14,132	10,539	39,990	35,270
Operating EBITDA (9)	($M)	72,646	84,771	52,113	226,575	136,703
Cash provided by operating activities	($M)	79,114	87,391	35,929	213,898	184,726
Capital expenditures (11)	($M)	103,220	61,214	2,905	178,799	83,232
Cash and cash equivalents – unrestricted	($M)	318,791	358,325	259,980	318,791	259,980
Restricted cash short and long-term	($M)	100,692	128,283	161,318	100,692	161,318
Total cash	($M)	419,483	486,608	421,298	419,483	421,298
Total debt and lease liabilities	($M)	563,173	565,238	557,182	563,173	557,182
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) (12)	($M)	401,148	468,424	352,058	401,148	352,058
Net debt (excluding Unrestricted Subsidiaries) (12)	($M)	130,680	138,701	113,054	130,680	113,054

1. Reference to crude oil or conventional 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 25.
3. Conventional 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 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 conventional 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 16.
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 16. This section also includes a description and details for all per boe metrics included in operating netback.
10. Net income (loss) attributable to equity holders of the Company.
11. Capital expenditures includes costs, net of income and cost from exploration and evaluation ("**E&E**") assets.
12. Refer to the "Non-IFRS Measures" section on page 16. ("**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

Third Quarter of 2021

Frontera continues to make significant progress against its key strategic priorities. During the quarter, the Company delivered value-focused production and cash flow from its Colombian operations, advanced its exciting exploration portfolio, delivered continuous operational improvements and greater cost efficiencies and maintained a strong balance sheet.

Frontera delivered solid financial and operating results in the third quarter of 2021. Compared to the second quarter of 2021, Frontera's production increased 2% to 36,422 boe/d, it's operating netback increased 15.2% to $37.79/boe, net sales realized price increased 6.8% to $59.47/boe, while transportation costs decreased 8.2% to $10.24/boe and production costs decreased 2.4% to $11.44/boe. Frontera increased full-year operating EBITDA to $360-$380 million, compared with the prior $325-$375 million guidance range.

Operationally, the Company drilled 15 wells and completed 27 workovers and well services during the third quarter of 2021. At Quifa, the Company drilled a new injector well which increased water handling capacity and production. Subsequent to the quarter at CPE-6, the Company grew production to approximately 5,000 bbl/d due to continued drilling and construction of additional water-handling facilities. At VIM-1, the Planadas-1 exploration well gas shows were encountered during drilling and a detailed logging program is now underway to identify zones for potential testing, and at the La Belleza discovery early production is expected to start in November 2021. In Ecuador, environmental licensing is complete and road construction is underway in advance of spudding the Jandaya-1 exploration well in the Perico block (Frontera 50% W.I. and operator, GeoPark 50% W.I.) in early December 2021. In the Espejo block (Frontera 50% W.I., GeoPark 50% W.I. and operator) 3D seismic acquisition of 60 sq km is expected to start in the fourth quarter.

During the third quarter of 2021, the Company repurchased for cancelation, 1,078,600 common shares at an approximate cost of $6.1 million. Year to date to November 2, the Company has repurchased 3.12 million shares for approximately $17 million for cancelation.

Year-to-date, the Company has produced 37,552 boe/d aligned with the guidance and expects a year end exit rate of over 40,000 boe/d 2021, has drilled 28 wells and completed 86 workovers and well services, released approximately $68.2 million of restricted cash, increased its uncollateralized credit lines to $90.3 million ($78.8 million used as of September 30, 2021), repurchased 2.9 million shares for approximately $15.3 million for cancellation.

On August 22, Frontera and majority-owned subsidiary and co-venturer CGX, also spud the Kawa-1 well in the Corentyne block, offshore Guyana. As of November 1, 2021, close to 78% of the planned footage has been drilled and the three main geological targets remain to be drilled. The Joint Venture continues to progress towards its total depth target in December 2021 in one of the most exciting exploration wells of this year. On November 1, 2021, the Company announced that it has acquired 45,083,314 Common Shares of CGX at a price of C$1.63 (equivalent of approximately $59.4 million) in connection with the Rights Offering previously announced by CGX on September 24, 2021, as a result Frontera increased its participation in CGX (on a non-diluted basis), from 73.85% to 76.98%. The Company also received 5-year warrants to purchase up to 1,173,774 Common Shares at an exercise price equal to US$1.51 per Common Share.

As part of Frontera's ongoing efforts to reduce exposure to liabilities and exploration commitments and focus on strategic asset, on October 22, 2021, the Company signed and closed a Sale and Settlement Agreement, transferring to Etablissement Maurel & Prom ("**EMP**") 49.999% of all issued and outstanding shares of the Maurel & Prom Colombia B.V. (**"M&P**") entity that holds 100% interests in the COR-15 and Muisca exploration licenses. Following the transaction, EMP and Frontera settled all mutual obligations, and Frontera reduced $17.2 million of minimum work commitments subsequent to September 30, 2021.

On November 1, 2021 the Company announced that the official webpage of the Colombian judicial branch reported that the Administrative Tribunal of Cundinamarca has approved the Conciliation Agreement (as defined below) between Frontera, Cenit Transporte y Logística de Hidrocarburos S.A.S. ("**Cenit**") and Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**"). Formalities are required in order for the mentioned decision to be in full force and effect. Consequently, the Parties agreed to extend the deadline of the Conciliation Agreement until November 30, 2021, to allow for formalities to be completed.

Financial and Operational Results

- Production averaged 36,422 boe/d (consisting of 17,371 bbl/d of light crude oil and medium crude oil, 18,168 bbl/d of heavy crude oil and 5,033 Mcf/d of conventional natural gas), compared with 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) in the prior quarter, and 43,202 boe/d (consisting of 19,820 bbl/d of light crude oil and medium crude oil, 21,997 bbl/d of heavy crude oil and 7,895 Mcf/d of conventional natural gas) in the third quarter of 2020.

- Cash provided by operating activities was $79.1 million, compared with $87.4 million in the prior quarter and $35.9 million in the third quarter of 2020. The Company reported a total cash position of $419.5 million at September 30, 2021, including $100.7 million of restricted cash. As at September 30, 2020, the total cash position was $421.3 million, including $161.3 million of restricted cash.
- Net income was $38.5 million ($0.40/share), compared with net loss of $25.6 million ($0.26/share) in the prior quarter, and net loss of $90.5 million ($0.93/share) in the third quarter of 2020.
- Capital expenditures were $103.2 million, compared with $61.2 million in the prior quarter and $2.9 million in the third quarter of 2020.
- Operating EBITDA was $72.6 million, compared with $84.8 million in the prior quarter, and $52.1 million in the third quarter of 2020. The decrease in operating EBITDA quarter over quarter was primarily a result of one less cargo sold during the third quarter and the corresponding increase in inventory which was sold early in the fourth quarter. This was partially offset by a decrease in realized loss on risk management contracts and a reversal of prior period cash royalties provision.
- Operating netback was $37.79/boe, compared with $32.80/boe in the prior quarter and $17.84/boe in the third quarter of 2020.

2. GUIDANCE

The Company has increased its annual Operating EBITDA guidance to $360-$380 million, compared to the prior $325-$375 million guidance range, the remaining results are expected to be within the estimated ranges. The following table reports the Company's actual results for the nine months period ending on September 30, 2021, against guidance.

		2021	
		Guidance	Actual
Average production	(boe/d)	37,500 to 39,500	37,552
Production costs	($/boe)	10.5 to 11.5	11.03
Transportation costs	($/boe)	10.0 to 11.0	10.91
Operating EBITDA (1)	($MM)	360 to 380	226.6
Development capital	($MM)	110 to 130	83.6
Exploration capital	($MM)	115 to 130	90.0
Infrastructure and other capital	($MM)	20 to 35	5.2
Capital expenditures (2)	($MM)	245 to 295	178.8

1. The updated guidance for Operating EBITDA assumes $72/bbl Brent and foreign exchange rate of 3700 COP to 1 USD.
2. Capital expenditures guidance does not include decommissioning costs estimated in $10 million (actual includes $4 million executed).

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia. Peru was reported until first quarter of 2020 when operations were suspended. Refer to the "Further Disclosures" section on page 25 for details of the Company's net production.

		Production				
Producing blocks in Colombia		**Q3 2021**	**Q2 2021**	**Q3 2020**	**YTD 2021**	**YTD 2020**
Heavy crude oil	(bbl/d)	18,168	17,241	21,997	18,791	25,495
Light and medium crude oil	(bbl/d)	17,371	17,535	19,820	17,859	20,793
Conventional natural gas	(mcf/d)	5,033	5,164	7,895	5,141	9,627
Total production Colombia	**(boe/d)**	**36,422**	**35,682**	**43,202**	**37,552**	**47,977**
Producing blocks in Peru						
Light and medium crude oil	(bbl/d)	—	—	—	—	1,788
Total production Peru	**(bbl/d)**	**—**	**—**	**—**	**—**	**1,788**
Total production	**(boe/d)**	**36,422**	**35,682**	**43,202**	**37,552**	**49,765**

Colombia

Production in Colombia for the three months ended September 30, 2021, increased by 2% compared to the prior quarter. Higher production was a result of the growth in production in the heavy oil unit, mainly in the CPE-6 and Quifa blocks resulting from water handling improvements during the third quarter.

Compared to the third quarter of 2020 and the nine months ended September 30, 2020, production decreased by 16% and 22%, respectively, as a result of natural decline due to 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 nine months ended September 30, 2021, and the third quarter of 2020 compared to 1,788 bbl/d in the nine months ended September 30, 2020. The service contract for Block 192 had no operations since February 2020, and expired on February 5, 2021, and was handed over to Perupetro. 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.

					Nine months ended September 30	
		Q3 2021	Q2 2021	Q3 2020	2021	2020
Production	(boe/d)	**36,422**	**35,682**	**43,202**	**37,552**	**49,765**
Royalties in-kind Colombia	(boe/d)	(3,435)	(2,904)	(2,987)	(3,036)	(3,460)
Royalties in-kind Peru [(1)]	(boe/d)	—	—	—	—	(295)
Net production	(boe/d)	**32,987**	**32,778**	**40,215**	**34,516**	**46,010**
Oil inventory (build) draw	(boe/d)	(4,972)	2,352	1,443	(1,139)	2,679
(Settlement) overlift	(boe/d)	(3)	16	—	(207)	(4)
Volumes purchased	(boe/d)	3,500	3,492	316	2,534	208
Other inventory movements [(2)]	(boe/d)	(1,833)	(1,917)	(1,529)	(1,845)	(2,004)
Sales volumes	(boe/d)	**29,679**	**36,721**	**40,445**	**33,859**	**46,889**
Sale of volumes purchased	(boe/d)	(3,007)	(2,570)	(449)	(2,095)	(200)
Sales volumes, net of purchases	(boe/d)	**26,672**	**34,151**	**39,996**	**31,764**	**46,689**
Oil sales volumes	(bbl/d)	25,773	33,258	38,651	30,864	45,037
Conventional natural gas sales volumes	(mcf/d)	5,124	5,090	7,667	5,130	9,416
Total oil and conventional natural gas sales volumes, net of purchases	(boe/d)	**26,672**	**34,151**	**39,996**	**31,764**	**46,689**
Inventory balance						
Colombia	(bbl)	943,121	488,828	708,103	943,121	708,103
Peru [(3)]	(bbl)	480,200	480,200	1,000,058	480,200	1,000,058
Inventory ending balance	**(bbl)**	**1,423,321**	**969,028**	**1,708,161**	**1,423,321**	**1,708,161**

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.

Sales volumes, net of purchases for the three months ended September 30, 2021, decreased by 22% compared with the prior quarter, due to one less cargo sold in Colombia during the third quarter, as Llanos Blend (12.7°API) oil inventory was built up at Puerto Bahia, which has been sold in November 2021. For the three and nine months ended September 30, 2021, sales volumes, net of purchases decreased by 33% and 32%, respectively, compared with the same periods of 2020, primarily due to lower volumes sales in Colombia as a consequence of the production decrease.

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).

		Q3 2021	Q2 2021	Q3 2020	YTD 2021	YTD 2020
PAP in cash	(bbl/d)	257	234	30	231	277
PAP in kind	(bbl/d)	1,143	413	—	529	86
PAP	**(bbl/d)**	1,400	647	**30**	760	363
% Production		**3.8 %**	**1.8 %**	**— %**	**2.0 %**	**0.7 %**

For the three and nine months ended September 30, 2021, PAP increased compared with the same periods of 2020, primarily due to higher WTI oil benchmark price.

Realized and Reference Prices

					Nine months ended September 30	
		Q3 2021	**Q2 2021**	**Q3 2020**	**2021**	**2020**
Reference price						
Brent	($/bbl)	73.23	69.08	43.34	67.97	42.53
Average realized prices						
Realized oil price, net of purchases	($/bbl)	68.70	65.67	40.78	64.18	37.47
Realized conventional natural gas price	($/mcf)	3.88	3.99	3.93	3.94	3.81
Net sales realized price						
Oil & gas sales, net of purchases	($/boe)	67.13	64.54	40.18	63.00	36.92
Realized (loss) gain on risk management contracts	($/boe)	(2.68)	(8.00)	(1.70)	(4.89)	3.83
Royalties	($/boe)	(4.83)	(0.53)	(0.23)	(2.26)	(0.61)
Diluent costs[1]	($/boe)	(0.15)	(0.34)	(1.62)	(0.97)	(1.76)
Net sales realized price	**($/boe)**	**59.47**	**55.67**	**36.63**	**54.88**	**38.38**

1. Beginning in the second quarter of 2021, the Company moved from using a third-party diluent service to buying its own diluent at the corresponding fields (mainly Quifa), using it for blending to meet pipeline specifications and other services, and then selling the blended oil at the sales point. The dollar difference between the cost of the purchases versus sales is approximately equivalent to how the Company accounted for the diluent costs in the past, or lower, considering the ability of the Company to secure better prices than a third-party diluent service. The decrease in diluent costs since the second quarter reflects decreased usage of the diluent service as the Company adopts this cost more efficient approach.

The average Brent benchmark price during the three and nine months ended September 30, 2021, increased by 69% and 60%, respectively, compared to the same periods of 2020. In comparison to the second quarter of 2021, the average Brent benchmark price increased by 6%. The increase in crude oil prices was mostly attributable to a better global economic outlook especially in Asia (China and India) and the COVID-19 vaccine rollouts. Also, Iran did not achieve a nuclear agreement with the USA delaying the return of an important amount of barrels to the market. Despite the fact that some countries such as the USA were asking for the OPEC+ coalition for production increase, the OPEC+ agreed on just a 400,000 bbl increase per month, leading to a market imbalance where demand is higher than supply.

For the three and nine months ended September 30, 2021, the Company's net sales realized price was $59.47/boe and $54.88/boe, respectively, an increase of 62% and 43% compared to the same periods of 2020. The increase is mainly the result of higher Brent benchmark price, and reduction in diluent costs due to replacement of the dilution service by volumes purchased, partially offset by, higher cash royalties resulting from the oil price increase, and the realized losses on risk management contracts during the nine months of 2021 compared to gain and a lower loss in the same periods of 2020. In comparison to the second quarter of 2021, the net sales realized price increased by 7%, or $3.80/boe, primarily driven by the increase in the benchmark oil price and lower losses on risk management contract during the third quarter of 2021, partially offset by higher royalties and wider differential during the third quarter of 2021.

Operating Netback

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

	Q3 2021		Q2 2021		Q3 2020	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price [(1) (2)]	145,947	59.47	173,008	55.67	134,771	36.63
Production costs [(3)]	(38,317)	(11.44)	(38,043)	(11.72)	(33,999)	(8.55)
Transportation costs [(4)]	(31,072)	(10.24)	(33,259)	(11.15)	(37,880)	(10.24)
Operating Netback [(5)]	**76,558**	**37.79**	**101,706**	**32.80**	**62,892**	**17.84**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes, net of purchases D&P - (boe) [(2) (6)]		26,672		34,151		39,996
Production [(7)]		36,422		35,682		43,202
Net production [(8)]		32,987		32,778		40,215

1. Per boe is calculated using produced sales volumes from D&P assets. Refer to "Realized and Reference Prices" on page 6.
2. Prior period figures are different compared with those previously reported as a result of the change in the treatment of purchased volumes and cost of purchases according with the current operating netback approach. Refer to "Non-IFRS Measures" section on page 16 for further details.
3. Per boe is calculated using production. Prior period figures are different compared with those previously reported as a result of a reclassification from production cost to transportation cost. Refer to "Selected Quarterly Information" section on page 14 for further details.
4. Per boe is calculated using net production after royalties.
5. Refer to the "Non-IFRS Measures" section on page 16 for details and a description of the operating netback calculation.
6. Sales volumes, net of purchases D&P exclude sales of third-party volumes and volumes from E&E assets as the related sales and costs are capitalized.
7. Refer to the "Production" section on page 4.
8. Refer to the "Further Disclosures" section on page 25.

Operating netback for the third quarter of 2021 was $37.79/boe, compared to $17.84/boe in the same quarter of 2020. The increase was primarily due to higher net sales realized price, partially offset by additional production costs per boe of $2.89, as a result of increase in the execution of maintenances and well services. Transportation cost per barrel was aligned with previous year.

In comparison to the second quarter of 2021, operating netback increased from $32.80/boe to $37.79/boe, due to higher net sales realized price and reduction in production costs and transportation cost during the third quarter.

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

	Nine months ended September 30			
	2021		2020	
	$M	**($/boe)**	**$M**	**($/boe)**
Net sales realized price [(1) (2)]	475,838	54.88	491,232	38.38
Production costs [(3)]	(113,115)	(11.03)	(137,765)	(10.10)
Transportation costs [(4)]	(102,804)	(10.91)	(147,157)	(11.67)
Operating Netback [(5)]	**259,919**	**32.94**	**206,310**	**16.61**
		(boe/d)		**(boe/d)**
Sales volumes, net of purchases D&P - (boe) [(2) (6)]		31,764		46,689
Production [(7)]		37,552		49,765
Net production [(8)]		34,516		46,010

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

Operating netback for the nine months ended September 30, 2021, increased by 98% to $32.94/boe from $16.61/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 Infrastructure Venture Inc. ("**IVI**") in the third quarter of 2020, the finalization of the take or pay contracts for the Monterrey - El Porvenir pipeline, for the Monterrey, Santiago and Oleoducto de Los Llanos Orientales ("**ODL**") offloading facilities partially offset by higher production cost per barrel mainly due to lower production.

Sales

($M)	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Oil & gas sales, net of purchases [1]	164,731	147,832	546,268	472,368
Realized (loss) gain on risk management contracts	(6,570)	(6,246)	(42,427)	49,129
Royalties	(11,848)	(861)	(19,598)	(7,761)
Diluent costs	(366)	(5,954)	(8,405)	(22,504)
Net sales	**145,947**	**134,771**	**475,838**	**491,232**
$/boe using sales volumes from D&P assets	59.47	36.63	54.88	38.38

1. "Oil & gas sales, net of purchases" is a non-IFRS measure and includes crude oil and conventional natural gas sales, net of the cost of the third-party volumes purchased. For further detail refer to the “Non-IFRS Measures” section on page 16.

Oil & gas sales, net of purchases increased by $16.9 million and $73.9 million for the three and nine months ended September 30, 2021, respectively, compared to the same periods of 2020, mainly due to higher Brent benchmark prices (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 nine months ended September 30, 2021, increased by $11.2 million and decreased by $15.4 million, respectively, compared with the same periods of 2020. The following table describes the various factors that impacted net sales:

($M)	Three months ended September 30	Nine months ended September 30
	2020-2021	2020-2021
Net sales for the period ended September 30, 2020	134,771	491,232
Increased due to 67% higher oil and gas price (YTD 71% higher)	99,187	333,536
Decrease due to lower volumes sold of 13,324 boe/d or 33% (YTD 14,925 boe/d or 32% lower)	(82,288)	(259,636)
Change to realized loss on risk management contracts	(324)	(91,556)
Decrease in diluent costs	5,588	14,099
Increase in royalties	(10,987)	(11,837)
Net sales for the period ended September 30, 2021	**145,947**	**475,838**

Oil and Gas Operating Costs

($M)	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Production costs	38,317	33,999	113,115	137,765
Transportation costs	31,072	37,880	102,804	147,157
Cost of purchases [1]	23,109	1,642	45,549	2,645
Diluent costs	366	5,954	8,405	22,504
Post termination cost	4,658	—	4,658	—
Overlift (settlement)	23	30	(2,638)	270
Inventory valuation	(12,247)	216	(3,782)	33,596
Total oil and gas operating costs	**85,298**	**79,721**	**268,111**	**343,937**

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 September 30, 2021, total oil and gas operating costs increased by 7% compared to the same period of 2020. For the nine months ended September 30, 2020 decreased 22% 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 13% for the three months ended September 30, 2021, compared with the same period of 2020, primarily due to additional execution of maintenances and well services activities. For the nine months ended September 30, 2021, production cost decreased 18% compared with the same period of 2020, primarily due to the closure of Peru operations since February 5, 2021, and reductions in variable cost in Colombia because of lower production.
- Transportation costs decreased by 18% and 30% for the three and nine months ended September 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, the finalization of the take or pay contracts for the Monterrey - El Porvenir pipeline, for the Monterrey, Santiago and ODL offloading facilities, and accounting eliminations from the consolidation of Puerto Bahia since the acquisition of control in IVI on August 6, 2020.

- Cost of purchases for the three and nine months ended September 30, 2021, increased by $21.5 million and $42.9 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. The sale of the volumes purchased represents an estimated income for the three and nine months ended September 30, 2021, of $19.3 million and $38.5 million respectively.
- Diluent costs decreased by 94% and 63% for the three and nine months ended September 30, 2021, compared with the same periods of 2020, mainly due to replacement of the dilution service by volumes purchased, lower diluent requirements resulting by the reduction in heavy oil production, optimization of dilution strategy of CPE-6 volumes moved to Puerto Bahia to sell as Llanos Blend, a new commercial segregation, and accounting eliminations from the consolidation of Puerto Bahia since the acquisition of control in IVI on August 6, 2020.
- Post-termination cost for the third quarter of 2021, includes environmental commitments, abandonment costs, and operational cost related to Block 192 in Peru, after the termination of the service contract on February 5, 2021.
- Overlift (settlement) was not significant for the third quarter of 2021. For the nine months ended September 30, 2021, decreased due to the settlement of an overlift balance during the first half of 2021.
- Inventory valuation for the third quarter of 2021, decreased by $12.5 million due to a buildup of inventory mainly at Puerto Bahia which has been sold in November 2021. For the nine months ended September 30, 2021, inventory valuation decreased by $37.4 million mainly due to the drawdown of inventory in Peru resulting from the volumes sold during 2020.

Costs Under Terminated Pipeline Contracts

For the three and nine months ended September 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 $19.6 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 September 30		Nine months ended September 30	
($M)	**2021**	**2020**	**2021**	**2020**
Royalties Colombia	11,848	861	19,598	7,718
Royalties Peru	—	—	—	43
Royalties	**11,848**	**861**	**19,598**	**7,761**
$/boe using sales volumes from D&P assets	4.83	0.23	2.26	0.61

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three and nine months ended September 30, 2021, royalties increased by $11.0 million and $11.8 million, respectively, compared to the same periods of 2020 primarily due to the increase in WTI oil benchmark price. Refer to the “Production Reconciled to Sales Volumes” section on page 5 for further details of royalties paid in-cash and in-kind.

Depletion, Depreciation and Amortization

	Three months ended September 30		Nine months ended September 30	
($M)	**2021**	**2020**	**2021**	**2020**
Depletion, depreciation and amortization	33,480	60,960	106,571	207,230

For the three and nine months ended September 30, 2021, depletion, depreciation and amortization expense (“**DD&A**”) decreased by 45% and 49%, respectively, compared to the same periods of 2020, mainly due to lower depletable base as a result of a reduction in abandonment cost, and lower capital expenditures from the second quarter 2020 until the first quarter 2021, as well the decrease in production and inventory buildup during the three and nine months ended September 30, 2021.

Impairment, Exploration Expenses and Other

($M)	Three months ended September 30 2021	2020	Nine months ended September 30 2021	2020
Impairment of:				
Properties plant and equipment	—	—	—	77,864
Intangible assets	—	—	—	54,881
Exploration and evaluation assets	—	—	—	17,839
Other	—	—	—	888
Total impairment	**—**	**—**	**—**	**151,472**
Exploration expenses	76	989	247	1,466
Expense (recovery) of asset retirement obligations	3,846	480	(3,003)	471
Impairment, exploration expenses and other	**3,922**	**1,469**	**(2,756)**	**153,409**

For the nine months ended September 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. Subsequently, the Company partially reversed this impairment charge in the fourth quarter of 2020 primarily due to the increase in oil prices. For further information refer to Note 8 of the 2020 Annual Consolidated Financial Statements.

During the three and nine months ended September 30, 2021, the Company recognized an expense related to the asset retirement obligation of $3.8 million and a recovery of $3.0 million, respectively, compared to an expense of $0.5 million and a recovery of $0.5 million in the same periods of 2020. When a decrease in the asset retirement obligations exceeds the carrying amount of the related asset, or there is an increase in the asset retirement obligations related to fully impaired or relinquished assets, the change is recognized as a recovery or expense of asset retirement obligations.

Other Operating Costs

($M)	Three months ended September 30 2021	2020	Nine months ended September 30 2021	2020
General and administrative	12,656	10,539	39,990	35,270
Share-based compensation	962	246	5,421	2,779
Restructuring, severance and other costs	954	1,047	2,870	13,757

General and Administrative

For the three and nine months ended September 30, 2021, G&A expenses increased 20% and 13% compared with the same periods of 2020, mainly due to the consolidation of Puerto Bahia since the acquisition of control in IVI on August 6, 2020, higher personnel expenses during 2021, additional professional fees related to the Conciliation Agreement, and increasing in G&A expenses at CGX subsidiary.

Share-based Compensation

For the three and nine months ended September 30, 2021, share-based compensation increased to $1.0 million and $5.4 million, respectively, from $0.2 million and $2.8 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 months ended September 30, 2021, restructuring, severance and other costs was comparable with the same period of 2020. For the nine months ended September 30, 2021, restructuring, severance and other costs decreased by $10.9 million, compared with the same period of 2020, primarily due to higher severance charges during early 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 September 30		Nine months ended September 30	
	2021	2020	2021	2020
Finance income	817	2,019	5,332	12,864
Finance expenses	(12,720)	(12,655)	(40,054)	(39,643)
Foreign exchange loss	(5,846)	(12,450)	(24,382)	(35,582)
Other loss, net	(570)	(38,626)	(13,353)	(44,285)
Reclassification of currency translation adjustments	—	(23,956)	—	(23,956)

Finance Income

For the three and nine months ended September 30, 2021, finance income decreased by $1.2 million and $7.5 million, respectively, mainly due to the accounting elimination of the interest income from the long-term receivable to IVI after its consolidation.

Finance Expense

For the three and nine months ended September 30, 2021, finance expenses increased by $0.1 million and $0.4 million compared to the same periods of 2020, mainly due to higher bank charges related to BTG's letters of credit.

Foreign Exchange Loss

For the three and nine months ended September 30, 2021, foreign exchange loss was $5.8 million and $24.4 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 $12.5 million and $35.6 million in the same periods of 2020.

Other Loss, net

For the three months ended September 30, 2021, the Company recognized other losses of $0.6 million, primarily related to the recognition of write down of assets. For the nine months ended September 30, 2021, recognized $13.4 million of legal claims related 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 17 of the Interim Financial Statements). For the three and nine months ended September 30, 2020, the Company recognized other loss of $38.6 million and $44.3 million, which was primarily related to a non-cash loss of $42.8 million resulting from the acquisition of IVI.

Reclassification of currency translation adjustments

During the third quarter of 2020, the Company recognized a non-cash loss of $24.0 million on the reclassification of Cumulative Foreign Currency Translation Adjustments ("**CTA**") from other equity reserves. The CTA loss primarily relates to historical functional currency COP to USD presentation currency translation differences on IVI, as an investment in associates.

(Loss) Gain on Risk Management Contracts

($M)	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Realized (loss) gain on risk management contracts(1)	(6,570)	(6,246)	(42,427)	49,129
Unrealized gain (loss) on risk management contracts(2)	4,068	(351)	2,683	(7,222)
Total (loss) gain on risk management contracts	(2,502)	(6,597)	(39,744)	41,907

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 nine months ended September 30, 2021, the realized loss on risk management contracts was $6.6 million and $42.4 million, compared to a loss of $6.2 million, and a gain of $49.1 million in the same periods of 2020, primarily from the cash settlement on 3-ways and Put Spreads contracts paid during the three and nine months ended September 30, 2021, at an average price of $62.85/bbl.

The unrealized gain on risk management contracts for the three and nine months ended September 30, 2021, was $4.1 million and $2.7 million, compared to a loss of $0.4 million and $7.2 million in the same periods of the previous year, primarily related to the reclassification of amounts to realized gain or loss from instruments settled during the period.

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. The Company's strategy aims to protect a minimum of 40%-60% of the estimated production with a tactical approach, using a combination of instruments, capped and non-capped, to protect the revenue generation and cash position of the Company, while maximizing the upside. This diversification of instruments allows the Company to take a more dynamic approach to the management of its hedging portfolio and balancing cash costs. In 2021, the Company executed a risk management strategy using a variety of derivatives instruments, including 3-ways, puts and put spreads primarily to protect against downward oil price movements. The Company's fourth quarter hedges do not materially cap upside price potential.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads ($/bbl)**	**Assets**	**Liabilities**
3-ways	October to December 2021	Brent	180,000	37.0/47.0/62.9	—	2,725
Put Spread	October to December 2021	Brent	1,254,000	40/50	56	—
Put	October to February 2022	Brent	1,539,000	60.0	1,239	—
Total as at September 30, 2021					**1,295**	**2,725**

Subsequent to September 30, 2021, the Company entered into new hedges to protect 2022 estimated production. The new transactions are as follows:

				Avg. Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put $**
Put	January to March 2022	Brent	550,000	60.0
Zero Cost Collar	January 2022	Brent	55,000	60 / 102
		Total (bbl)	**605,000**	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. The Company monitors its exposure to such foreign currency risks. As at September 30, 2021, the Company has outstanding 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	October to December 2021	COP / USD	$ 60,000	3,500 / 4,120	—	123
Total as at September 30, 2021					**—**	**123**

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

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 (as defined below). Refer to "Liquidity and Capital Resources" section on page 18 for further information. As at September 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	October 2021 to June 2025	LIBOR + 180	121,100	3.9%	—	9,407
Total as at September 30, 2021					**—**	**9,407**

Income Tax Recovery (Expense)

	Three months ended September 30		Nine months ended September 30	
($M)	**2021**	**2020**	**2021**	**2020**
Current income tax expense	(174)	(2,805)	(24,390)	(9,061)
Deferred income tax recovery (expense)	14,166	—	(12,767)	(167,979)
Total income tax recovery (expense)	**13,992**	**(2,805)**	**(37,157)**	**(177,040)**

Current income tax expense for the third quarter of 2021 was $0.2 million, compared with $2.8 million in the same quarter of 2020. The reduction is mainly due to the reduction in the minimum tax rate in Colombia from 0.5% to 0% for 2021. Deferred income tax recovery for the third quarter of 2021 was $14.2 million compared with $Nil, mainly due to the recognition of $25.1 million of deferred tax asset recognized as a result of the increase in the income tax rate in Colombia according to the new tax legislation recently approved (for further information refer to Note 7 of the Interim Financial Statements) partially offset by, $10.5 million from the deferred tax asset utilization.

For the nine months ended September 30, 2021, the current income tax expense was $24.4 million, compared with $9.1 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 nine months ended September 30, 2021, was $12.8 million compared with $168.0 million in the same period of 2020. The 2021 expense is due to $36.6 million of deferred tax asset utilization partially offset by, $25.1 million of additional deferred tax asset explained above. 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 in 2020.

Net Income (loss)

	Three months ended September 30		Nine months ended September 30	
($M)	**2021**	**2020**	**2021**	**2020**
Net income (loss) attributable to equity holders of the Company	38,531	(90,473)	(1,243)	(546,042)
Per share – basic ($)	0.40	(0.93)	(0.01)	(5.64)
Per share – diluted ($)	0.39	(0.93)	(0.01)	(5.64)

The Company reported a net income of $38.5 million for the third quarter of 2021 which included operating income by $40.0 million, and deferred income tax recovery of $14.2 million partially offset by $12.7 million of finance costs expenses, and a loss on risk management contracts of $2.5 million. This compared to a net loss of $90.5 million in the third quarter of 2020, which included a loss of $66.8 million resulting from the acquisition of IVI due to the reclassification of currency translation adjustment and a non-cash loss in the transaction, and operating loss of $12.8 million.

For the nine months ended September 30, 2021, the Company reported a net loss of $1.2 million which included a debt extinguishment costs of $29.1 million, total income tax expense of $37.2 million, a loss on risk management contracts of $39.7 million, finance costs expenses of $40.1 million, other loss of $13.4 million partially offset by $157.1 million of operating income. This compared to a net loss of $546.0 million in the in the same period 2020, which included a loss from operations of $307.8 million (including a non-cash impairment charge of $153.4 million), loss of $66.8 million resulting from the acquisition of IVI due to the reclassification of currency translation adjustment and a non-cash loss in the transaction, and the derecognition of deferred tax assets of $168.0 million.

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
($M)	**2021**	**2020**	**2021**	**2020**
Development capital	38,327	354	83,646	58,150
Exploration activities (1)	62,317	1,788	89,970	23,778
Infrastructure and other capital	2,576	763	5,183	1,304
Total capital expenditures	**103,220**	**2,905**	**178,799**	**83,232**

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

Capital expenditures for the three and nine months ended September 30, 2021, were $103.2 million and $178.8 million, respectively. Compared to the same periods of 2020, capital expenditure increased by $100.3 million and $95.6 million, respectively, mainly due to the following:

- During the three and nine months ended September 30, 2021, development capital increased by $38.0 million and $25.5 million, respectively, compared to the same periods of 2020, mainly due to a total of 15 and 28 development wells drilled in Quifa, CPE-6, Guatiquia and La Creciente blocks, respectively. During the third quarter of 2020, the Company did not drill any development well, and for the nine months ended September 30, 2020, drilled 21 development wells in Quifa, CPE-6, and Sabanero blocks.
- For the three and nine months ended September 30, 2021, exploration activities increased by $60.5 million and $66.2 million mainly as a result of exploration activities in Guyana. On August 22, 2021, the Company, through its majority-owned subsidiary and joint venture partner CGX, spud Kawa-1 exploration well in the Corentyne block. Also, after preparation activities on the VIM-1 Block in Colombia, the Basilea-1 well was drilled in July, encountering gas shows through the shallower Porquero Formation and has been temporarily suspended. During the three and nine months ended September 30, 2020, Nil and one exploration well was drilled respectively.

- During the three and nine months ended September 30, 2021, infrastructure and other capital increased by $1.8 million and $3.9 million, mainly due to works related to the construction of the Berbice Deep Water Port in Guyana.

Selected Quarterly Information

		2021			2020				2019
Operational and financial results		**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Heavy crude oil production	(bbl/d)	18,168	17,241	20,997	21,074	21,997	22,533	31,996	32,586
Light and medium crude oil production	(bbl/d)	17,371	17,535	18,685	19,756	19,820	18,415	29,539	36,095
Total crude oil production	(bbl/d)	35,539	34,776	39,682	40,830	41,817	40,948	61,535	68,681
Conventional natural gas production	(mcf/d)	5,033	5,164	5,227	6,356	7,895	9,399	11,611	12,677
Total production	(boe/d)	36,422	35,682	40,599	41,945	43,202	42,597	63,572	70,905
Sales volumes, net of purchases (D&P) - (boe)(1)	(boe/d)	26,672	34,151	34,555	44,551	39,966	35,963	34,186	65,646
Brent price	($/bbl)	73.23	69.08	61.32	45.26	43.34	33.39	50.82	62.42
Oil & gas sales, net of purchases (1)	($/boe)	67.13	64.54	58.18	42.20	40.18	24.96	41.57	58.56
Realized (loss) gain on risk management contracts	($/boe)	(2.68)	(8.00)	(3.53)	(2.00)	(1.70)	12.19	2.65	(0.66)
Royalties	($/boe)	(4.83)	(0.53)	(1.96)	(0.47)	(0.23)	—	(1.18)	(0.98)
Diluent costs (2)	($/boe)	(0.15)	(0.34)	(2.25)	(1.85)	(1.62)	(2.63)	(1.36)	(1.16)
Net sales realized price (2)	($/boe)	59.47	55.67	50.44	37.88	36.63	34.52	41.68	55.76
Production costs (2)	($/boe)	(11.44)	(11.72)	(10.06)	(12.95)	(8.55)	(8.68)	(12.12)	(13.47)
Transportation costs (2)	($/boe)	(10.24)	(11.15)	(11.30)	(11.36)	(10.24)	(11.56)	(12.75)	(13.09)
Operating netback	($/boe)	37.79	32.80	29.08	13.57	17.84	14.28	16.81	29.20
Revenue	($M)	182,673	224,685	184,734	177,109	152,760	81,701	236,938	351,027
Net income (loss)	($M)	38,531	(25,648)	(14,126)	48,636	(90,473)	(67,760)	(387,809)	69,408
Per share – basic ($)	($)	0.40	(0.26)	(0.14)	0.50	(0.93)	(0.70)	(4.04)	0.71
Per share – diluted ($)	($)	0.39	(0.26)	(0.14)	0.48	(0.93)	(0.70)	(4.04)	0.70
General and administrative	($M)	12,656	14,132	13,202	19,851	10,539	9,716	15,015	22,897
Operating EBITDA	($M)	72,646	84,771	69,158	35,639	52,113	37,608	46,982	137,052
Capital expenditures	($M)	103,220	61,214	14,365	24,871	2,905	15,651	64,676	132,452

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 16 for further details.

2. Prior period figures are different compared with those previously reported as a result of a reclassification from production cost to transportation cost and diluent cost by approximately ($0.40/boe), $0.30/boe and $0.10/boe per quarter, respectively. The reclassification was related to certain logistic and refining processes fees of own crude oil previously recorded as production cost.

Over the past eight quarters, the Company’s sales have fluctuated due to changes in production, movement in Brent benchmark prices, timing of cargo shipments, and fluctuations in crude oil price differentials. In addition to decreases in the Company’s production since 2019 due to natural declines in its mature fields, during the past six 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, and the cessation of production in Peru since March 2020, however in the current quarter this tendency changed and production started to go up. In addition, 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 income (loss) are also impacted most significantly by the recognition and derecognition of deferred income taxes, 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 22 for further details), DD&A, and total (loss) gain from risk management contracts that fluctuate with changes in hedging strategies and crude oil benchmark forward prices.

Refer to the Company’s previously issued annual and interim Management Discussion and Analysis available on SEDAR at www.sedar.com for further information regarding changes in prior quarters.

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 94.18% through the conversion of certain debt into preferred shares with voting rights.

For the nine months ended September 30, 2021, Puerto Bahia has generated $30.1 million of segment income from operations (2020: $5.2 million since acquisition date on August 6, 2020) primarily from take-or-pay contracts in its liquid bulk storage terminal business. Prior to the acquisition of a controlling interest in Puerto Bahia the Company recognized $18.0 million as its share of losses from IVI mainly due to higher unrealized foreign exchange losses on the revaluation of Puerto Bahia's USD-denominated bank debt.

ODL Pipeline

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

For the nine months ended September 30, 2021, the Company recognized $28.3 million as its share of income from ODL which was $3.2 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 nine months ended September 30, 2021, the Company recognized gross dividends of $41.6 million and a return of capital of $4.2 million. As at September 30, 2021, the Company has accounts receivables of $8.7 million dividends from ODL.

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 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" section on page 22 for further details.

As at September 30, 2021, the Company has recorded a carrying value of dividends receivable from Bicentenario of $55.5 million and the balance of the investment in Bicentenario of $59.2 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:

($M)	Three months ended September 30		Nine months ended September 30	
	2021	**2020**	**2021**	**2020**
Revenue	17,625	11,323	52,899	11,323
Costs	(5,426)	(3,152)	(14,741)	(3,152)
General and administrative expenses	(1,255)	(1,235)	(4,550)	(1,235)
Depletion, depreciation and amortization	(1,205)	(1,773)	(2,911)	(1,773)
Restructuring, severance and other costs	(578)	—	(578)	—
Segment income from operations	**9,161**	**5,163**	**30,119**	**5,163**
Share of Income from associates - ODL	8,691	9,190	28,282	31,484
Share of Income from associates - Bicentenario	—	5,527	—	16,662
Share of income (loss) from associates - IVI	—	476	—	(18,023)
Segment income	**17,852**	**20,356**	**58,401**	**35,286**

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. Refer to the "Liquidity and Capital Resources" section on page 18.

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

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

($M)	Three months ended September 30		Nine months ended September 30	
	2021	**2020**	**2021**	**2020**
Net income (loss)	38,531	(90,473)	(1,243)	(546,042)
Finance income	(817)	(2,019)	(5,332)	(12,864)
Finance expenses	12,720	12,655	40,054	39,643
Income tax (recovery) expense	(13,992)	2,805	37,157	177,040
Depletion, depreciation and amortization	33,480	60,960	106,571	207,230
Impairment and others	3,846	480	(3,003)	151,943
Costs under terminated pipeline contracts	—	8,391	—	19,621
Share-based compensation	962	246	5,421	2,779
Restructuring, severance and other costs	954	1,047	2,870	13,757
Share of income from associates	(8,691)	(15,193)	(28,282)	(30,123)
Foreign exchange loss	5,846	12,450	24,382	35,582
Other loss, net	570	38,626	13,353	44,285
Unrealized (gain) loss on risk management contracts	(4,068)	351	(2,683)	7,222
Non-controlling interests	3,305	(2,169)	8,198	2,674
Loss on extinguishment of debt	—	—	29,112	—
Reclassification of currency translation adjustments	—	23,956	—	23,956
Operating EBITDA	**72,646**	**52,113**	**226,575**	**136,703**

Net Sales

Net sales are a non-IFRS subtotal that adjusts revenue to include realized gains and losses from risk management contracts while removing the cost of dilution activities, including the cost of any volumes purchased from third parties. This is a useful indicator for management, as the Company hedges a portion of its oil production using derivative instruments to manage exposure to oil price volatility. This metric allows the Company to report its realized net sales after factoring in these risk management activities. The deduction for 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 exclude 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 8.

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 7.

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 September 30		Nine months ended September 30	
	2021	2020	2021	2020
Oil and gas sales ($M) [1]	187,840	149,474	591,817	475,013
(-) Cost of purchases ($M) [2]	(23,109)	(1,642)	(45,549)	(2,645)
Oil & gas sales, net of purchases ($M)	**164,731**	**147,832**	**546,268**	**472,368**
Sales volumes, net of purchases (D&P) - (boe)	2,453,824	3,679,632	8,671,572	12,792,786
Oil & gas sales, net of purchases ($/boe)	67.13	40.18	63.00	36.92

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 15.
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 September 30		Nine months ended September 30	
	2021	2020	2021	2020
Net sales ($M)	145,947	134,771	475,838	491,232
Sales volumes, net of purchases (D&P) - (boe)	2,453,824	3,679,632	8,671,572	12,792,786
Net sales realized price ($/boe)	59.47	36.63	54.88	38.38

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

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Production costs ($M)	38,317	33,999	113,115	137,765
Production (boe)	3,350,824	3,974,577	10,251,696	13,635,610
Production costs ($/boe)	11.44	8.55	11.03	10.10

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

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Transportation costs ($M)	31,072	37,880	102,804	147,157
Net production (boe)	3,034,804	3,699,780	9,422,868	12,606,740
Transportation costs ($/boe)	10.24	10.24	10.91	11.67

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 September 30
($M)	**2021**
Long-term debt	391,168
Total lease liabilities (1)	8,427
Risk management liabilities, net (2)	1,553
Consolidated Total Indebtedness excluding 2025 Puerto Bahia Debt	**401,148**
(-) Cash and Cash Equivalents (3)	(270,468)
(=) Net Debt excluding 2025 Puerto Bahia Debt	**130,680**

1. Excludes $0.5 million of lease liabilities attributable to the Unrestricted Subsidiaries.
2. Excludes $9.4 million of risk management liabilities attributable to the Unrestricted Subsidiaries.
3. Includes Cash and cash equivalents attributable to the guarantors and borrower.

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 of September 30, 2021, the Company had a total cash balance of $419.5 million (including $100.7 million in restricted cash), which is $18.3 million higher than December 31, 2020. For the nine months ended September 30, 2021, the Company generated $213.9 million in operating cash flows which were used to fund cash outflows of $67.5 million for capital expenditures and other investing activities. For the nine months ended September 30, 2021, financing activities generated net outflows of $53.8 million as a result of the repayment of $373.3 million of the Company's 9.7% senior unsecured notes due 2023 (the "**2023 Unsecured Notes**") and the transaction cost of the Company's offering of $400 million in senior unsecured notes at a coupon rate of 7.875% maturing in 2028 which was completed on June 21, 2021 (the "**2028 Unsecured Notes**"), $23.9 million of interest and other financing charges, $20.0 million of 2025 Puerto Bahia Debt payments, $15.3 million common shares repurchased, $10.6 million in lease payments, and $8.1 million of dividends paid to non-controlling interest, partially offset by, a net cash inflow of $397.4 million ($400 million issuances minus $2.6 million of issue price) from the 2028 Unsecured Notes. As a result, the working capital deficit was reduced to $39.7 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 September 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 20 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 September 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 September 30, 2021, total restricted cash of $100.7 million, decreased by $68.2 million from December 31, 2020, primarily due to the release $22.3 abandonment funds that were replaced with letters of credit, $13.9 million of closed legal processes, and $31.6 million released due to the reduction in cash collateral requirements of exploration commitments and the 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 23.

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.

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

On July 7, 2021, the Company redeemed all of the remaining 2023 Unsecured Notes at a redemption price comprised of (i) 104.85% of the aggregate principal amount of the 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 (as defined in the indenture), 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.

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 2028 Unsecured Notes, the Company (excluding the Unrestricted Subsidiaries) may, among other things, incur indebtedness provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.25:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.25:1.0. In the event that these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $100.0 million and 10% of consolidated net tangible assets(3) and Indebtedness in respect of the Puerto Bahia Funding up to $44.7 million. The 2028 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at September 30, 2021, the Company is in compliance with all such covenants.

As of September 30, 2021, and pursuant to requirements under the Indenture, the Company reports consolidated total indebtedness of $401,148,000 consolidated adjusted EBITDA of $274.798,000 and consolidated interest expense of $31.826,000.

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 16.

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

2. Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most recent 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.

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 September 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. 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 September 30, 2021, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $83.2 million.

Commitments and Contractual Obligations

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

As at September 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	1,149	5,545	3,028	93	57	—	9,872
2025 Puerto Bahía Debt and interest (1)	21,424	47,126	49,982	47,651	13,591	—	179,774
Total financial obligations	**$ 38,323**	**$ 84,171**	**$ 84,510**	**$ 79,244**	**$ 45,148**	**$ 478,750**	**$ 810,146**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	$ 17,462	$ 69,850	$ 69,850	$ 69,850	$ 35,030	$ —	$ 262,042
Other transportation agreements	1,674	306	—	—	—	—	1,980
Exploration commitments							
Minimum work commitments (2) (3)	22,730	90,024	87,608	30,779	—	—	231,141
Other commitments							
Operating purchases, leases and community obligations	4,038	16,086	9,068	8,107	7,603	1,416	46,318
Total Commitments	**$ 45,904**	**$ 176,266**	**$ 166,526**	**$ 108,736**	**$ 42,633**	**$ 1,416**	**$ 541,481**

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 COR-15 and Muisca blocks by $17.2 million, subsequent to September 30, 2021, the Company transfer its rights and obligations on these blocks to M&P. For further information refer to Note 18 of the Interim Financial Statements.
3. 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 September 30, 2021, the Company, through its 73.85% interest in CGX, has exploration work commitments under its Petroleum Prospecting Licenses ("**PPL**") for Guyana blocks, as follows:

- In accordance with the Corentyne PPL, which is currently in phase one of the second renewal period, one exploration well must be drilled by November 26, 2021.
- In accordance with the Demerara PPL, which is currently in phase one of the second renewal period, one 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 exploratory well by June 15, 2022.

The Company, through its interest in CGX, has entered into agreements for activities to complete its requirements under the Corentyne and Demerara contracts, and for the port. As at September 30, 2021, aggregate minimum future obligation still outstanding under these agreements is $35.9 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 drilling agreement, the Company has provided a deed of guarantee in the event of non-performance by CGX for certain obligations up to a maximum of $25.0 million.

Oleoducto Central de Colombia ("Ocensa") P-135 Ship-or-Pay Agreement

On April 29, 2020, Ocensa and the Company entered into a pledge agreement pursuant to which the Company guaranteed payment to Ocensa through a pledge of the crude oil transported in the Ocensa Pipeline. The term of the pledge agreement has been amended and extended until March 31, 2022. During the term of the pledge agreement, Ocensa has agreed not to exercise its early termination and prepayment rights. The pledge agreement will automatically terminate if the Company subsequently meets certain credit conditions set forth in the ship-or-pay agreement.

Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company's financial position, results of operations or cash flows. Other than as disclosed below, no material changes have occurred in contingencies during the third quarter. For additional detail or previously disclosed matters refer to Note 28 - Commitments and Contingencies of the 2020 Annual Financial Statements and Note 17 of the Interim Financial Statements.

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 approval of a 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 had delivered its opinion on the Conciliation Agreement. The opinion was favorable, recommending that the conciliation be approved.

On November 1, 2021, the Company announced that the official webpage of the Colombian judicial branch reported that the Administrative Tribunal of Cundinamarca has approved the Conciliation Agreement between Frontera, Cenit and Bicentenario. Formalities are required in order for the mentioned decision to be in full force and effect. Consequently, the Parties agreed to extend the deadline until November 30, 2021, to allow for formalities to be completed. The terms of the Conciliation Agreement remain the same as previously disclosed.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at November 2, 2021:

	Number
Common shares	95,418,479
Deferred share units ("**DSUs**") (1)	737,805
Restricted share units ("**RSUs**") (2)	2,019,684

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 nine months ended September 30, 2021, the Company purchased 1,078,600 and 2,866,100 Common Shares, respectively, under the new NCIB. As at November 2, 2021, the Company had repurchased for cancellation a total of 3,121,000 Common Shares for $17.1 million with an additional 2,076,612 Common Shares available for repurchase under the NCIB.

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

	Nine months ended September 30 2021
Number of common shares repurchased	2,866,100
Total amount of common shares repurchased ($M)	15,344
Weighted-average price per share ($)	5.35

6. RELATED-PARTY TRANSACTIONS

The following tables provide the total balances outstanding (before impairment), commitments and transactional amounts with related parties, as at September 30, 2021, and December 31, 2020, and for the three and nine months ended September 30, 2021 and 2020, respectively:

September 30, 2021 and December 31, 2020		Accounts Receivable (1)	Accounts Payable	Cash Advance (1)
ODL	2021	8,629	318	—
	2020	465	7,821	—
Bicentenario	2021	66,561	—	87,278
	2020	70,761	—	87,278

		Three Months Ended September 30		Nine Months Ended September 30	
($M)		Purchases / Services	Interest Income (1)	Purchases / Services	Interest Income (1)
ODL	2021	5,140	—	21,493	—
	2020	7,690	—	28,119	—
Bicentenario	2021	—	—	—	—
	2020	160	—	1,427	—
IVI (2)	2021	—	—	—	—
	2020	3,415	1,533	22,479	10,558

1. Amounts presented based on contractual payment obligations undiscounted and prior to impairments.
2. 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 conventional natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events 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 18 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 nine months ended September 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 on February 5, 2021. Under this contract, the volumes produced were owned by Perupetro and the Company was entitled to in-kind payments on production, which ranged from 44% to 84% of production on the block. The Company reported the share of production retained by the government under the contract as royalties paid in-kind in this MD&A.

The following table includes the average net production:

		Net Production				
Producing blocks in Colombia		**Q3 2021**	**Q2 2021**	**Q3 2020**	**YTD 2021**	**YTD 2020**
Heavy crude oil	(bbl/d)	15,986	15,802	20,443	17,126	23,513
Light and medium crude oil	(bbl/d)	16,118	16,070	18,387	16,488	19,315
Conventional natural gas	(mcf/d)	5,033	5,164	7,895	5,141	9,627
Net production Colombia	**(boe/d)**	**32,987**	**32,778**	**40,215**	**34,516**	**44,517**
Producing blocks in Peru						
Light and medium crude oil	(bbl/d)	—	—	—	—	1,493
Net production Peru (1)	**(bbl/d)**	**—**	**—**	**—**	**—**	**1,493**
Total net production	**(boe/d)**	**32,987**	**32,778**	**40,215**	**34,516**	**46,010**

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

Overlift and Settlement

Overlift and settlement corresponds to a short-term imbalance between the Company's production and sales volumes. In these instances, the Company lifts barrels from the pipeline system resulting in more volumes sold than produced, which is considered "overlift." Overlift represents an obligation for the Company to deliver the equivalent future production. Settlement occurs when this production is delivered to settle the overlift liability. During overlift, the Company recognizes the sales and an equivalent cost with no margin or operating EBITDA impact during the quarter. When the overlift is settled, this expense is reversed to recognize the gross margin and operating EBITDA earned on the related sale in the period of production. Refer to the "Oil and Gas Operating Costs" section on page 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
bbl/d	Barrels of oil per day
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
COP	Colombian pesos
C$	Canadian dollars
D&P	Development and producing
E&E	Exploration and evaluation
MMbbl	Millions of oil barrels
Mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
PAP	High-price clause participation
Q	Quarter
USD	United States dollars
WTI	West Texas Intermediate
W.I	Working interest
$	U.S. dollars
$M	Thousand U.S. dollars
$MM	Million U.S. dollars