MANAGEMENT DISCUSSION & ANALYSIS

March 3, 2021
For the year ended December 31, 2020

*Frontera Energy Corporation ("**Frontera**" or the "**Company**") is an oil and gas company formed and existing under the laws of British Columbia, Canada, that is engaged in the exploration, development and production of crude oil and natural gas in South America, and is committed to working hand in hand with all its stakeholders to conduct business in a socially and environmentally responsible manner. The Company's Common Shares ("**Common Shares**") are listed and publicly traded on the Toronto Stock Exchange ("**TSX**") under the trading symbol "FEC." The Company's head office is located at 333 Bay Street, Suite 1100, Toronto, Ontario, Canada, M5H 2R2, and its registered office is 1055 West Georgia Street, 1500 Royal Centre, P.O. Box 11117, Vancouver, British Columbia, Canada V6E 4N7.*

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 Consolidated Financial Statements and related notes for the years ended December 31, 2020 and 2019 ("**Annual Consolidated Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly Interim Condensed Consolidated Financial Statements and Company's 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 21.*

Certain statements in this MD&A constitute forward-looking statements or "forward-looking information (collectively, "forward-looking statements") within the meaning of applicable securities legislation, which involve known and unknown risks, uncertainties, and other factors that may cause the actual results, performance or achievements of the Company or industry results to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as "expects," "does not expect," "is expected," "anticipates," "does not anticipate," "plans," "planned," "estimates," "estimated," "projects," "projected," "forecasts," "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal" or "objective." In addition, forward-looking statements often state that certain actions, events or results "may," "could," "would," "might" or "will" be taken, may occur or be achieved. Such forward-looking statements, including, but not limited to, statements with respect to estimates and/or assumptions in respect of the impact of a sustained low oil price environment due to the ongoing impacts of the COVID-19 pandemic, and actions of the Organization of Petroleum Exporting Countries and non-OPEC countries, the expected impact of measures that the Company has taken and continues to take in response to these events, expectations regarding the Company's ability to manage its liquidity and capital structure and generate sufficient cash to support operations, capital expenditures and financial commitments, the timing of release of restricted cash, the impact of fluctuations in the price of, and supply and demand for oil and natural gas products, production levels, cash levels, reserves, capital expenditures (including plans and projects related to drilling, exploration activities, and infrastructure and the timing thereof), operating EBITDA, production costs, transportation costs, the impact of the Conciliation Agreement and obtaining regulatory approvals, and statements regarding the implementation of an NCIB and the Company's dividend policy 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 Annual Information Form AIF for the year ended December 31, 2020, dated March 3, 2021 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.

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent that they involve oil and gas that will be encountered only if the property in question is developed. The estimated reserve values disclosed in this MD&A do not represent fair market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates for all properties due to the effects of aggregation.

*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. MESSAGE TO THE SHAREHOLDERS

By any measure, 2020 was one of the most challenging and tumultuous years in a generation. The impacts of the COVID-19 pandemic were felt in all parts of business, government and daily life. The oil and gas industry was no exception. Significant decreases in oil prices brought on by lower demand due to the pandemic severely impacted sector bottom lines as global oil supply vastly outpaced demand.

For Frontera, the decline in oil prices in 2020 and the uncertainty and challenges brought on by the pandemic were an opportunity to take meaningful steps to not only weather the storm but make substantive changes across our business. In April 2020, we voluntarily shut-in our higher cost production, reduced capital spending and accelerated cost reduction initiatives across the Company. These actions not only preserved our strong financial position during an uncertain time, but also represented an inflection point for Frontera as we strive to become a stronger, more resilient, returns-focused company.

I am extremely proud of what our team accomplished in 2020 under such difficult circumstances. We reduced capital expenditures by 69% compared to 2019, focusing spending on our core business unit in Colombia. We stabilized our production at 41,945 boe/d in the fourth quarter of 2020. We reduced production costs from $11.99/boe in 2019 to $11.13/boe in 2020, a 7% decrease and we reduced transportation costs from $12.51/boe in 2019 to $11.27/boe in 2020, a 10% decrease and we expect the cost efficiencies we achieved in 2020 to be permanent, improving our cost structure and competitiveness going forward. We also reduced G&A by 28%, making difficult decisions to reduce headcount, salaries and cash compensation for management and board members. By taking these decisive actions, we exited 2020 with a strong total cash position of $401.2 million including restricted cash.

Despite weathering the worst crisis in recent history Frontera also delivered several key objectives for the year:

- We substantially resolved the Company’s largest contingent liability by reaching a pipeline settlement agreement in Colombia, pending final approvals.
- We added 24.8 MMboe of Proved plus Probable (“2P”) reserves on a net basis, achieved a reserves replacement ratio RRR of 154% and extended our 2P reserves life index to 10.3 years compared to 6.7 years at year end 2019.
- We achieved exploration success at the La Belleza well on VIM-1 and continued development of the CPE-6 field – two exciting opportunities that we believe will accelerate renewal in our portfolio.
- We advanced our Guyana exploration opportunity, identifying exciting prospectivity in our two deep water blocks while securing additional time to complete our work plans.
- We delivered production at the high end of our revised August 2020 guidance.
- We made the decision to transition out of Peru and some of the highest cost, highest carbon barrels in our portfolio.
- We transformed the cost structure of the Company, demonstrating resilience to a very low oil price environment and making Frontera a more competitive company.

Importantly, we achieved these results without sacrificing our commitment to health and safety. Frontera reduced its total recordable incident rate by 16% compared to 2019, maintaining a safe and healthy working environment in all of our operating areas. We also increased our support for local communities in Colombia and Peru by providing safety, medical and food supplies.

We also made significant progress on standardizing our approach to Ethics, Social and Governance (ESG) across our business and we were proud to be recently recognized by Ethisphere as one of the world's most ethical companies in 2021.

Looking ahead, I am very pleased to pass the leadership baton to Orlando Cabrales, who I have known for many years and deeply respect. Under his leadership, I am assured that Frontera is well positioned to successfully pursue the great opportunities that are before it.

I am confident that Frontera is now stronger, more resilient and more competitive. I would like to thank our employees for their tireless efforts and commitment to safely and responsibly operating throughout all the challenges and uncertainty of 2020. I also look back upon what the leadership team, with the guidance of our Board, has accomplished over the past three years since I became CEO with genuine pride, and I look forward to the Company’s continued success in 2021 and beyond.

Richard Herbert
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q4 2020	Q3 2020	Q4 2019	Year ended December 31 2020	Year ended December 31 2019
Operational Results						
Oil production -Colombia	(bbl/d)	40,830	41,817	58,517	44,916	61,224
Oil production -Peru	(bbl/d)	—	—	10,164	1,339	7,250
Natural gas production -Colombia	(boe/d)	1,115	1,385	2,224	1,545	2,401
Production (1)	(boe/d) (2)	41,945	43,202	70,905	47,800	70,875
Oil and gas sales	($/boe)	42.20	40.17	58.95	38.24	60.13
Realized (loss) gain on risk management contracts	($/boe)	(2.00)	(1.68)	(0.66)	2.41	(0.43)
Royalties	($/boe)	(0.47)	(0.23)	(0.98)	(0.57)	(1.86)
Diluent costs	($/boe)	(1.76)	(1.95)	(1.09)	(1.84)	(1.69)
Net sales realized price (3)	($/boe)	37.97	36.31	56.22	38.24	56.15
Production costs (4)	($/boe)	(13.46)	(8.97)	(13.76)	(11.13)	(11.99)
Transportation costs (5)	($/boe)	(10.93)	(9.89)	(12.84)	(11.27)	(12.51)
Operating netback (6)	($/boe)	13.58	17.45	29.62	15.84	31.65
Financial Results						
Oil and gas sales	($M)	173,047	149,474	356,922	648,060	1,351,071
Realized (loss) gain on risk management contracts	($M)	(8,205)	(6,246)	(4,006)	40,924	(9,720)
Royalties	($M)	(1,925)	(861)	(5,904)	(9,686)	(41,770)
Diluent costs	($M)	(7,225)	(7,244)	(6,581)	(31,213)	(38,064)
Net sales (6)	($M)	155,692	135,123	340,431	648,085	1,261,517
Net income (loss) (7)	($M)	48,636	(90,473)	69,408	(497,406)	294,287
Per share – basic	($)	0.50	(0.93)	0.71	(5.13)	3.01
Per share – diluted	($)	0.48	(0.93)	0.70	(5.13)	2.96
General and administrative	($M)	19,851	10,539	22,897	55,121	76,072
Operating EBITDA (6)	($M)	35,639	52,113	137,052	172,342	586,158
Cash provided by operating activities	($M)	42,055	35,929	151,575	226,781	546,967
Capital expenditures (8)	($M)	24,871	2,905	132,452	108,103	345,919
Cash and cash equivalents – unrestricted	($M)	232,288	259,980	328,433	232,288	328,433
Restricted cash short and long-term	($M)	168,934	161,318	127,378	168,934	127,378
Total cash	($M)	401,222	421,298	455,811	401,222	455,811
Total debt and lease liabilities	($M)	538,244	557,182	402,660	538,244	402,660
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) (9)	($M)	362,001	352,058	392,587	362,001	392,587
Net debt (excluding Unrestricted Subsidiaries) (9)	($M)	146,978	113,054	81,628	146,978	81,628

1. Represents working interest production before royalties and total volumes produced from service contracts. Refer to the “Further Disclosures” section on page 29.
2. Boe has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.
3. Per boe is calculated using sales volumes from development and producing (“**D&P**”) assets.
4. Per boe is calculated using production.
5. Per boe is calculated using net production after royalties.
6. Refer to the “Non-IFRS Measures” section on page 17. This section also includes a description and details for all per boe metrics included in operating netback.
7. Net (loss) income attributable to equity holders of the Company.
8. Capital expenditures includes costs, net of income from exploration and evaluation (“**E&E**”) assets.
9. Refer to the “Non-IFRS Measures” section on page 17. (“**Unrestricted Subsidiaries**”) include CGX Energy Inc.(“**CGX**”), ODL JV Ltd. (“**ODL JV**”) (formerly Pacific Midstream Ltd.), and Frontera Bahía Holding Ltd (formerly Pacinfra Holding Ltd) including its subsidiary Sociedad Portuaria Puerto Bahía S.A.(“**Puerto Bahia**”).

.

Performance Highlights

Full Year 2020

- Production averaged 47,800 boe/d, which is at the upper end of guidance for 2020, compared with 70,875 boe/d in 2019. Colombia delivered production of 46,461 boe/d compared with 63,325 boe/d in 2019 as the Company proactively curtailed its capital program and shut-in production due to falling global commodity prices and ongoing impacts of COVID-19 pandemic, combined with the natural decline of mature blocks. In Peru, production from Block 192 was suspended in February 2020 with volumes remaining shut-in through the end of the year.
- Cash provided by operating activities was $226.8 million, compared with $547.0 million in 2019, contributing to a total cash position at December 31, 2020, of $401.2 million compared with $455.8 million as at December 31, 2019. Total cash includes $168.9 million of restricted cash compared with $127.4 million as at December 31, 2019.
- Net loss was $497.4 million ($5.13/share), compared with net income of $294.3 million ($3.01/share) in 2019.
- Capital expenditures were $108.1 million, compared with $345.9 million in 2019, as the Company focused its 2020 capital budget on activities that remained economic at low oil prices; primarily essential maintenance, workovers and activities that sustain production from higher netback fields.
- Operating EBITDA was $172.3 million, compared with $586.2 million in 2019.
- Operating netback was $15.84/boe, compared with $31.65/boe in 2019.

Fourth Quarter 2020

- Production averaged 41,945 boe/d, compared with 70,905 boe/d in the fourth quarter of 2019.
- Cash provided by operating activities was $42.1 million, compared with $151.6 million in the fourth quarter of 2019.
- Net income was $48.6 million ($0.50/share), compared with net income of $69.4 million ($0.71/share) in the fourth quarter of 2019.
- Capital expenditures were $24.9 million, compared with $132.5 million in the fourth quarter of 2019.
- Operating EBITDA was $35.6 million, compared with $137.1 million in the fourth quarter of 2019.
- Operating netback was $13.58/boe, compared with $29.62/boe in the fourth quarter of 2019.

Oil and Gas Reserves

- Frontera delivered 154% 2P reserves replacement, added 24.8 MMboe of 2P net reserves and extended its reserve life index to 10.3 years at year end 2020.
- Frontera's 2020 year-end net 2P reserves additions of 30.6 MMboe were primarily driven by technical revisions, the La Belleza discovery in the VIM-1 block, reduction of in-kind royalty payments and reduction in high-price participation ("PAP") royalties related to the Quifa block. These additions were primarily offset by 16.1 MMboe of 2020 production and the de-booking of 5.7 MMboe of reserves in Block 192 and Z-1 in Peru, and the Orito field in Colombia as the Company pursues its exit from these areas. All of the Company's booked reserves for the year ended December 31, 2020 are located in Colombia.

3. GUIDANCE

The Company's 2020 financial and operational results were in-line with its revised guidance, with the exception of production costs which were affected by several one-time events. The year-end results continue to demonstrate the Company's ability to deliver stable production with ongoing focus on cost reductions and efficiency improvements throughout the business.

2020 production results were on the high end of guidance: full year production averaged 47,800 boe/d, on guidance of 46,000 to 48,000 boe/d, and second half production averaged 42,574 boe/d, on guidance of 40,000 to 43,000 boe/d.

Production costs increased in the fourth quarter of 2020 as a result of a strengthening Colombian Peso ("**COP**") versus the USD, significant catch-up spending by the Company on previously deferred operations and maintenance activity, performance-based compensation costs, provision for remediation costs in Peru, and an increase in energy input costs as commodity prices improved. As a result, full year 2020 production costs averaged $11.13/boe, above the guidance of $9.5 to $10.5/boe, and second half production costs averaged $11.18/boe, above guidance of $8.0 to $9.0/boe.

Transportation costs were in-line with guidance, averaging $11.27/boe on a full-year 2020 basis, within guidance of $11.0 to $12.0/boe, and averaging $10.40/boe on a second half basis, within guidance of $9.5 to $10.5/boe. Transportation costs during the second half of the year were positively impacted by the consolidation of certain related party contracts due to the Company's acquisition of a controlling interest in Puerto Bahia.

Capital expenditures totaled $108.1 million in 2020, at the midpoint of revised guidance, and included the consolidation impact of capital expenditures related to CGX (net impact of $2.0 million), which was not considered in the revised guidance for 2020. Likewise, second half capital expenditures totaled $27.8 million, in-line with the guidance of $20 to $40 million.

		Actual		Guidance	
		Second-half 2020	FY 2020	Second-half 2020	FY 2020
Average production	(boe/d)	42,574	47,800	40,000 to 43,000	46,000 to 48,000
Production costs	($/boe)	11.18	11.13	8.0 to 9.0	9.5 to 10.5
Transportation costs	($/boe)	10.40	11.27	9.5 to 10.5	11.0 to 12.0
Capital expenditures	($MM)	27.8	108.1	20 to 40	100 to 120

2021 Guidance

The Company expects its total 2021 capital program to be approximately $200–$295 million on a consolidated basis. This includes $110–$130 million in development capital to maintain the Company's production volume delivering 40,500–42,500 boe/d, and $70–$130 million on exploration activities in Colombia, Guyana, and Ecuador. Approximately 55% of the total expected exploration capital will be invested in Guyana principally to drill the Kawa-1 well offshore, with the Company's share of that cost dependent on whether or not it elects to pursue strategic options. The remaining capital budget of $20–$35 million will be directed towards infrastructure investments (including the Berbice port in Guyana) and other assets.

Production costs are expected to average $10.0–$11.0/boe, lower at the midpoint compared with full year 2020 results. Transportation costs are expected to average $10.5–$11.5/boe, in-line with full year 2020 results. Transportation costs include the estimated impact from the sale of the remaining oil inventory in Peru ($0.50/boe) and the new take or pay contracts resulting from the pipeline settlement announced on November 17, 2020 ($0.20/boe on a full year basis assuming the settlement is approved around mid-year). The Company anticipates generating an Operating EBITDA of $275–$325 million in 2021, using a Brent oil price assumption of $60/bbl and a USD/COP exchange rate of 3500:1.

		2021 Guidance
Average production	(boe/d)	40,500 to 42,500
Production costs	($/boe)	10.0 to 11.0
Transportation costs	($/boe)	10.5 to 11.5
Operating EBITDA	($MM)	275 to 325
Development capital	($MM)	110 to 130
Exploration capital	($MM)	70 to 130
Infrastructure and other capital	($MM)	20 to 35
Capital expenditures (1)	($MM)	200 to 295

1. Capital expenditures do not include decommissioning costs. The Company expects to execute $10 million of decommissioning in 2021 including $4 million in Peru.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2020, the Company received an independent certified reserves evaluation report ("**Reserves Report**") from DeGolyer and MacNaughton for all of its assets, with total net 2P reserves of 166.4 MMboe compared with 157.7 MMboe certified reserves in 2019. The 2P reserves additions of 30.6 MMboe were primarily driven by technical revisions of 18.9 MMboe at the Coralillo, Quifa SW, Hamaca, Jaspe, Ceibo and Copa fields, 6.4 MMboe from the La Belleza discovery in the VIM-1 block, reduction of in-kind royalty payments, and reduction in PAP royalties related to the Quifa block. These additions were primarily offset by 16.1 MMboe of 2020 production and the de-booking of 5.7 MMboe reserves in Block 192 and Z-1 in Peru, and the Orito field in Colombia as Frontera pursues its exit from these areas. Proved net reserves of 102.2 MMboe now represent 61% of the total 2P reserves compared with 66% of the total 2P reserves in 2019.

The Reserves Report were prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and the National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities.

Concurrently, with the filing of this MD&A, the Company has filed the following: (i) the Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1, (ii) Report on Reserves Data by Independent Qualified Reserves Evaluator on Form

51-101F2 by DeGolyer and MacNaughton, and (iii) the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3. These reports have been filed on SEDAR at www.sedar.com.

Reserves at December 31, 2020 (MMboe [1] [5])								
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Quifa SW block	49.9	46.1	7.6	6.8	57.5	52.9	Heavy oil
	Other heavy oil blocks [2]	29.8	29.0	28.4	28.1	58.2	57.1	Heavy oil
	Light/medium oil blocks [3]	24.9	23.7	24.2	23.4	49.1	47.1	Light and medium oil, associated natural gas
	Natural gas blocks [4]	3.4	3.4	5.9	5.9	9.3	9.3	Natural gas and associated liquids
	Total as at Dec. 31, 2020	**108.0**	**102.2**	**66.0**	**64.2**	**174.0**	**166.4**	Oil and natural gas
	Total as at Dec. 31, 2019	115.4	104.8	55.8	52.9	171.2	157.7	
	Difference	(7.4)	(2.6)	10.2	11.3	2.8	8.7	
	2020 Production	17.4	16.1	**Total reserves incorporated**		20.2	24.8	

1. See “Boe Conversion” in the “Further Disclosures” section on page 29.

2. Includes Cajua and Jaspe fields in Quifa Block and, Sabanero and CPE-6 blocks.
3. Includes Cubiro, Cravoviejo, Canaguaro, Guatiquia, Casimena, Corcel, Neiva, Cachicamo, Guaduas and other producing blocks.
4. Includes La Creciente and VIM 1 Blocks.
5. In the table above, “Gross” refers to working interest before royalties, and “Net” refers to working interest after royalties. Numbers in the table may not add due to rounding differences.

5. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company’s operations in Colombia and Peru. Refer to the “Further Disclosures” section on page 29 for details of the Company’s net production.

	Production (in boe/d)				
Producing blocks in Colombia	**Q4 2020**	**Q3 2020**	**Q4 2019**	**FY 2020**	**FY 2019**
Heavy oil	21,074	21,997	32,586	24,384	32,412
Light and medium oil	19,756	19,820	25,931	20,532	28,812
Natural gas	1,115	1,385	2,224	1,545	2,401
Total production Colombia	**41,945**	**43,202**	**60,741**	**46,461**	**63,625**
Producing blocks in Peru					
Light and medium oil	—	—	10,164	1,339	7,250
Total production Peru	**—**	**—**	**10,164**	**1,339**	**7,250**
Total production	**41,945**	**43,202**	**70,905**	**47,800**	**70,875**

Colombia

Production in Colombia for the three months ended December 31, 2020, decreased by 3% to 41,945 boe/d, compared to the prior quarter and by 31% compared to the same period of 2019, mainly due to water disposal restrictions in Quifa SW, natural decline in some of the Company’s mature blocks and reduced capital investment during 2020. For the year ended December 31, 2020, production decreased by 17,164 boe/d, or 27% compared with 2019 as a result of the voluntary shut-in of production from certain fields with lower field netbacks, including the highest water cut wells in Quifa, and natural declines as capital spending was significantly reduced during the second and third quarters of 2020. This voluntary shut-in of production was part of the Company’s program to manage the impact of the COVID-19 pandemic and lower oil price environment.

Peru

The Company reported no production in Peru for the third and fourth quarters of 2020 compared with 10,164 bbl/d in the fourth quarter of 2019. For the year ended December 31, 2020, production decreased to 1,339 bbl/d from 7,250 bbl/d in 2019. On February 27, 2020, Block 192 was placed in force majeure as a result of a community blockade. Effective July 30, 2020, the Company notified Perupetro S.A. (“**Perupetro**”), Peru’s state oil and gas company, that the force majeure was lifted. The Company did not resume operations or production thereafter. The service contract expired on February 5, 2021.

Production Reconciled to Sales Volumes

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

					Year ended December 31	
		Q4 2020	**Q3 2020**	**Q4 2019**	**2020**	**2019**
Production	**(boe/d)**	**41,945**	**43,202**	**70,905**	**47,800**	**70,875**
Royalties in-kind Colombia	(boe/d)	(2,818)	(2,987)	(4,584)	(3,299)	(5,007)
Royalties in-kind Peru (1)	(boe/d)	—	—	(1,631)	(221)	(1,122)
Net production	**(boe/d)**	**39,127**	**40,215**	**64,690**	**44,280**	**64,746**
Oil inventory draw (build)	(boe/d)	6,443	1,443	3,941	3,625	(619)
Overlift positions	(boe/d)	609	—	(19)	153	2
Other inventory movements (2)	(boe/d)	(1,602)	(1,213)	(2,803)	(1,750)	(2,568)
Sales volumes	**(boe/d)**	**44,577**	**40,445**	**65,809**	**46,308**	**61,561**
Oil sales volumes	(bbl/d)	43,516	39,100	63,638	44,805	59,221
Natural gas sales volumes	(boe/d)	1,061	1,345	2,171	1,503	2,340
Inventory balance						
Colombia	(bbl)	119,792	708,103	904,648	119,792	904,648
Peru	(bbl)	995,585	1,000,058	1,382,754	995,585	1,382,754
Inventory ending balance	**(bbl)**	**1,115,377**	**1,708,161**	**2,287,402**	**1,115,377**	**2,287,402**

1. The Company reports the share of production retained by the government of Peru as royalties paid in-kind. Refer to the "Peru Royalties - Block 192 Contract" section on page 29.
2. Mainly corresponds to operational consumption and quality volumetric compensation.

Sales volumes for the three months ended December 31, 2020, were higher than the prior quarter by 10%, due to the drawdown of inventory volumes in Colombia and an overlift liability position of 56 Mbbl at the end of 2020. In comparison to the fourth quarter of 2019, sales volumes decreased by 32% mainly due to lower production and no volumes sold in Peru. Sales volumes for the year ended December 31, 2020, decreased by 25%, compared with 2019 primarily due to lower production partially offset by the drawdown of oil inventory in Colombia and Peru.

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).

		Three months ended December 31		Year ended December 31	
		2020	**2019**	**2020**	**2019**
PAP in cash	(bbl/d)	70	926	225	1,239
PAP in kind	(bbl/d)	—	168	65	408
PAP	**(bbl/d)**	**70**	**1,094**	**290**	**1,647**
% Production		**0.2 %**	**1.5 %**	**0.6 %**	**2.3 %**

For the three months and year ended December 31, 2020, PAP decreased compared with the same periods of 2019 primarily due to lower WTI oil benchmark prices.

Realized and Reference Prices

		Q4 2020	Q3 2020	Q4 2019	Year ended December 31 2020	Year ended December 31 2019
Reference price						
Brent	($/bbl)	45.26	43.34	62.42	43.21	64.16
Average realized prices						
Realized oil price	($/bbl)	42.34	40.78	60.27	38.63	61.74
Realized natural gas price	($/boe)	23.72	22.40	20.04	22.06	19.21
Net sales realized price						
Oil and gas sales	($/boe)	42.20	40.17	58.95	38.24	60.13
Realized (loss) gain on risk management contracts (1)	($/boe)	(2.00)	(1.68)	(0.66)	2.41	(0.43)
Royalties	($/boe)	(0.47)	(0.23)	(0.98)	(0.57)	(1.86)
Diluent costs	($/boe)	(1.76)	(1.95)	(1.09)	(1.84)	(1.69)
Net sales realized price	**($/boe)**	**37.97**	**36.31**	**56.22**	**38.24**	**56.15**

1. In the second quarter of 2020, the Company reported a gain of $27.3 million ($1.61/boe) from the unwinding of risk management contracts. Refer to the "(Loss) Gain on Risk Management Contracts" section on page 12 for further details.

The average Brent benchmark price during the three months and year ended December 31, 2020, decreased by 27% and 33%, respectively, compared with the same periods of 2019. The reduction in crude oil prices was mostly attributable to a weaker global economic outlook and lower crude oil demand resulting from the COVID-19 pandemic and related supply-demand market imbalances. In comparison to the third quarter of 2020, the Brent benchmark price increased by 4% as a result of OPEC and Russia maintaining the production cuts of 7.7 MMbbl/day to compensate for an oversupplied market, strong demand returning in Asia (primarily China and India), expectations surrounding the COVID-19 vaccine rollout and weakness of the USD.

For the three months and year ended December 31, 2020, the Company's net sales realized price was $37.97/boe and $38.24/boe, respectively, a decrease of 32%, compared with both of the same periods of 2019 due to lower Brent benchmark prices and wider differentials, for year ended December 31, 2020 the reduction was partially offset by a realized gain on risk management contracts mainly resulting from the unwinding of contracts in the second quarter of 2020. In comparison to the third quarter of 2020, the Company's net sales realized price for the fourth quarter of 2020 increased by 5%, or $1.66/boe, primarily due to the improvement in the Brent benchmark price, partially offset by higher royalties and realized losses on expiring risk management contracts.

Operating Netback

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

	Q4 2020		Q3 2020		Q4 2019	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	155,692	37.97	135,123	36.31	340,431	56.22
Production costs (2)	(51,930)	(13.46)	(35,646)	(8.97)	(89,789)	(13.76)
Transportation costs (3)	(39,354)	(10.93)	(36,585)	(9.89)	(76,428)	(12.84)
Operating Netback (4)	**64,408**	**13.58**	**62,892**	**17.45**	**174,214**	**29.62**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes (D&P) (5)		44,577		40,445		65,809
Production (6)		41,945		43,202		70,905
Net production (7)		39,127		40,215		64,690

1. Per boe is calculated using sales volumes from D&P assets. Refer to the "Realized and Reference Prices" on page 7.
2. Per boe is calculated using production.
3. Per boe is calculated using net production after royalties.
4. Refer to the "Non-IFRS Measures" section on page 17 for details and a description of the operating netback calculation.
5. Sales volumes D&P assets exclude volumes from E&E assets as the related sales and costs are capitalized under IFRS.
6. Refer to the "Production" section on page 5.
7. Refer to the "Further Disclosures" section on page 29.

Operating netback for the fourth quarter of 2020 was $13.58/boe, compared to $29.62/boe in the same quarter of 2019. The decrease was primarily due the reduction in the Company's net sales realized price, partially offset by lower production costs per boe resulting from the closure of Block 192 in Peru, renegotiation of contract rates with suppliers, and other operational optimizations impacting personnel costs, fuel consumption, internal field transport, maintenance and well services, chemical treatment, and rental expenses. Transportation cost per boe decreased due to the cessation of payments for unused facilities under the BIC Ancillary Agreements and the CLC Ancillary Agreements (refer to “Termination of Transportation Agreements” section on page 22 for further details) and accounting eliminations from the consolidation of Puerto Bahia since its acquisition in the third quarter of 2020.

In comparison to the third quarter of 2020, operating netback for the fourth quarter of 2020 decreased from $17.45/boe to $13.58/boe, primarily due to higher production costs as a result of a provision for remediation costs in Peru ($1.43/boe), higher maintenance (mainly well services and internal road maintenance) executed during the fourth quarter to maintain production levels; and a stronger COP and lower production volumes which negatively impacted production and transportation costs on a per barrel basis.

The following table provides a summary of the Company’s annual operating netback for the following years:

	Year ended December 31			
	2020		2019	
	$M	**($/boe)**	**$M**	**($/boe)**
Net sales realized price [(1)]	648,085	38.24	1,261,517	56.15
Production costs [(2)]	(194,770)	(11.13)	(310,084)	(11.99)
Transportation costs [(3)]	(182,597)	(11.27)	(295,554)	(12.51)
Operating Netback [(4)]	**270,718**	**15.84**	**655,879**	**31.65**
		(boe/d)		**(boe/d)**
Sales volumes (D&P) [(5)]		46,308		61,561
Production [(6)]		47,800		70,875
Net production [(7)]		44,280		64,746

References 1 through 7 are consistent with those included in the quarterly operating netback table above.

Operating netback for 2020 was $15.84/boe compared with $31.65/boe in 2019. The decrease was primarily driven by the reduction in the Company’s net sales realized price partially offset by lower production cost due to the closure of Block 192 in Peru, temporary shut-in of production from higher cost wells in Colombia, renegotiation of contract rates with suppliers, and various operational optimizations. Transportation cost per boe decreased due to operational optimizations, take or pay volumes deferred to the first half of 2021, the cessation of payments under the BIC Ancillary Agreements and CLC Ancillary Agreements (refer to “Termination of Transportation Agreements” section on page 22 for further details), and a reduction resulting from the acquisition of Infrastructure Ventures Inc. (“**IVI**”) after accounting eliminations.

Sales

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Oil and gas sales[(1)]	173,047	356,922	648,060	1,351,071
Realized (loss) gain on risk management contracts[(2)]	(8,205)	(4,006)	40,924	(9,720)
Royalties	(1,925)	(5,904)	(9,686)	(41,770)
Diluent costs	(7,225)	(6,581)	(31,213)	(38,064)
Net sales	**155,692**	**340,431**	**648,085**	**1,261,517**
$/boe using sales volumes from D&P assets	37.97	56.22	38.24	56.15

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. Includes a net gain of $27.3 million for the year ended December 31, 2020 from the early termination of risk management contracts. Refer to the “(Loss) Gain on Risk Management Contracts” section on page 12 for further details.

Oil and gas sales for the three months and year ended December 31, 2020, decreased by $183.9 million and $703.0 million respectively, compared to the same periods of 2019, mainly due to lower oil prices and reduced sales volumes on lower production. Refer to the “Production” section on page 5 for the further detail on changes in productions volumes.

Net sales for the three months and year ended December 31, 2020, decreased by $184.7 million and $613.4 million, respectively, compared with the same periods of 2019. The following table describes the various factors that impacted net sales:

	Three months ended December 31	Year ended December 31
($M)	**2020-2019**	**2020-2019**
Net sales for the period ended December 31, 2019	340,431	1,261,517
Decrease due to 28% lower oil and gas price (FY 36% lower)	(101,444)	(491,887)
Decrease due to lower volumes sold of 21,232 boe/d or 32% (FY 15,253 boe/d or 25% lower)	(82,431)	(211,124)
Higher realized (loss) gain on risk management contracts	(4,199)	50,644
(Increase) decrease in diluent costs	(644)	6,851
Decrease in royalties	3,979	32,084
Net sales for the period ended December 31, 2020	**155,692**	**648,085**

Royalties

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	2019
Royalties Colombia	1,925	5,721	9,643	41,023
Royalties Peru	—	183	43	747
Royalties	**1,925**	**5,904**	**9,686**	**41,770**
$/boe using sales volumes from D&P assets	0.47	0.98	0.57	1.86

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three months and year ended December 31, 2020, royalties decreased by $4.0 million and $32.1 million, respectively, compared to the same periods of 2019 primarily due to lower oil prices and reduced production. Refer to the "Production Reconciled to Sales Volumes" section on page 6 for further details of royalties paid in-cash and in-kind.

Oil and Gas Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Production costs	51,930	89,789	194,770	310,084
Transportation costs	39,354	76,428	182,597	295,554
Diluent costs	7,225	6,581	31,213	38,064
Overlift	2,700	353	2,970	512
Inventory valuation	4,180	13,318	37,776	(7,628)
Total oil and gas operating costs	**105,389**	**186,469**	**449,326**	**636,586**

For the three months and year ended December 31, 2020, total oil and gas operating costs decreased by 43% and 29%, respectively, compared to the same periods of 2019. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs for the three months and year ended December 31, 2020 were 42% and 37% lower than the comparable periods of 2019, primarily due to lower production as a result of the voluntary shut-in of higher cost wells in Colombia and the closure of Block 192 in Peru. In response to the decline in oil prices during 2020, the Company took significant steps to optimize its production costs by renegotiating key contractor rates, eliminating non-essential maintenance, and limiting staff and contractors to minimal operational levels. These actions resulted in the reduction of personnel costs, fuel consumption, internal field transport, maintenance and well services, chemical treatment, and rental expenses.
- Transportation costs for the three months and year ended December 31, 2020, were 49% and 38% lower than the same periods of 2019, primarily due to lower volumes transported, the deferral of take or pay volumes to the first half of 2021, the cessation of payments for unused facilities under the BIC Ancillary Agreements and the CLC Ancillary Agreements, and accounting eliminations from the consolidation of Puerto Bahia since its acquisition in the third quarter of 2020.
- Diluent costs in the fourth quarter of 2020, were 10% higher than the same quarter of 2019, mainly due to favorable natural gasoline market conditions in the prior year. For the year ended December 31, 2020, diluent costs decreased by 18% compared to 2019 mainly due to lower consumption during 2020.
- Overlift for the three months and year ended December 31, 2020, was higher than the comparable periods in 2019 due to an overlift liability balance of 56 Mbbl as at December 31, 2020.

- Inventory valuation expense for the fourth quarter of 2020, was $9.1 million lower compared with the same quarter of 2019 resulting from the drawdown of higher cost crude oil inventory at the end of 2019. For the year ended December 31, 2020, inventory valuation expense increased by $45.4 million compared with 2019 due to the drawdown of crude oil inventory levels during the year.

Costs Under Terminated Pipeline Contracts

For the three months and year ended December 31, 2020, the Company recorded non-cash disputed charges of $99.1 million and $118.7 million, respectively, which includes $96.3 million related to the Conciliation Agreement (refer to "Conciliation Agreement" section on page 22), and $22.4 million in relation to the BIC Ancillary Agreements and CLC Ancillary Agreements (refer to "Termination of Transportation Agreements" section on page 22 for further details). Prior to the cessation of payments under these agreements, the Company had recorded these charges as transportation costs totalling $8.0 million ($1.35/boe) during the fourth quarter of 2019, and $33.1 million ($1.40/boe) for the year ended December 31, 2019.

Depletion, Depreciation and Amortization

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Depletion, depreciation and amortization	51,637	89,753	258,867	376,010

For the three months and year ended December 31, 2020, depletion, depreciation and amortization expense ("**DD&A**") decreased by 42% and 31%, respectively, compared to the same periods of 2019, mainly due to lower production levels in 2020.

Impairment, Exploration Expenses and Other

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
(Reversal) impairment of:				
Properties plant and equipment	(43,129)	—	34,735	—
Intangible assets	—	—	54,881	—
Exploration and evaluation assets	32,019	1,838	49,858	19,526
Other	1,603	—	2,491	4,745
Other assets	—	—	—	36,628
Total (reversal) impairment	**(9,507)**	**1,838**	**141,965**	**60,899**
Exploration expenses	2,410	595	3,876	3,658
(Recovery) expense of asset retirement obligations	(4,923)	1,551	(4,452)	2,681
Impairment, exploration expense and other	**(12,020)**	**3,984**	**141,389**	**67,238**

For the three months ended December 31, 2020, the Company recognized a net impairment reversal of $43.1 million as certain factors were identified which indicated that impairment charges recorded during the first quarter of 2020 had decreased. Specifically, the Company's certified 2020 year-end reserves report resulted in an increase in the total proved and probable reserves and a higher net present value than the carrying amount of its oil and gas properties. As a result, the Company performed an impairment reversal test and concluded that the recoverable amount for the Central Cash Generating Units ("**CGU**") exceeded its carrying amount resulting in a reversal of previous impairment charges of $50.7 million. This reversal was offset by an impairment charge of $7.5 million relating to the South CGUs.

In addition, an impairment charge of $32.0 million was recorded as a result of non-commercial exploratory test results and plans to abandon further work on E&E assets mainly in the Guama Block, and $1.6 million of other impairment charges relating to obsolete materials inventory in Peru.

For the year ended December 31, 2020, the Company recognized impairment charges of $142.0 million, primarily, due to lower forecasted oil prices which reduced the expected future cash flows of its CGU. As a result of the impairment test, the carrying amounts of certain assets relating to the Colombia CGUs were reduced to their recoverable amounts. The recoverable amount of each CGU was determined based on the Company's updated projections of future cash flows generated from proved and probable reserves. For further information refer to Note 8 of the Annual Consolidated Financial Statements.

For the three months and year ended December 31, 2020, the Company recorded exploration expenses of $2.4 million and $3.9 million, respectively, related to costs incurred prior to obtaining the legal rights to explore an area, including geological and geophysical costs, including payroll, and payments made to fulfill the remaining balance of minimum exploration work commitment for certain blocks.

For the year ended December 31, 2019, the Company recognized an impairment charge of $36.6 million related to a long-term receivable from IVI as a result of uncertainties relating to future projects and a reduction in future cash flows of Puerto Bahia.

Additionally, for the three months and year ended December 31, 2019, the Company recognized impairment charges of $1.8 million and $19.5 million, respectively, of E&E assets mainly due to technical results and changes in development plans for certain exploration projects from Colombia. Impairment charges of $4.7 million was recognized related to slow moving or obsolete inventories.

Other Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	2020	2019	2020	2019
General and administrative	19,851	22,897	55,121	76,072
Share-based compensation	1,181	(124)	3,960	2,907
Restructuring, severance and other costs	7,340	2,994	21,097	11,945

General and Administrative

For the three months and year ended December 31, 2020, G&A expenses decreased 13% and 28%, respectively, compared with the same periods of 2019, mainly due to costs efficiencies, reduced discretionary spending and lower personnel costs from organizational restructuring activities.

Share-based Compensation

For the three months and year ended December 31, 2020, shared-based compensation was comparable with the same periods of 2019. Share-based compensation reflects non-cash charges relating to the vesting of restricted and 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 and year ended December 31, 2020, restructuring, severance and other costs increased by $4.3 million and $9.2 million, respectively, compared with same periods of 2019, primarily due to post-termination obligations mainly related to the Block 192 and higher severance charges and non-cash charges from the modification of certain leased assets, including a reduction of the Company's office space, as part of the actions taken to streamline operations in response to the lower oil price environment.

Non-Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	2020	2019	2020	2019
Finance income	6,665	3,162	19,529	20,244
Finance expenses	(18,778)	(17,438)	(58,421)	(65,492)
Foreign exchange gain (loss)	27,840	(8,812)	(7,742)	(10,264)
Other (loss) income, net	(3,043)	(6,680)	(47,328)	2,758
Reclassification of currency translation adjustments	—	—	(23,956)	—

Finance Income

For the three months ended December 31, 2020, finance income increased by $3.5 million mainly as a result of the accretion income on dividends from Bicentenario which had been discounted in previous years. For the year ended December 31, 2020, a reduction of $0.7 million of finance income resulted from the accounting elimination of the interest income from the long-term receivable of Puerto Bahia after its consolidation and lower interest income earned on cash balances.

Finance Expense

For the three months ended December 31, 2020, finance expense increased by $1.3 million mainly due to the interest expense from Puerto Bahia after its consolidation. For the year ended December 31, 2020, finance expense decreased by $7.1 million, compared with 2019, mainly due to the discounting of dividends declared by Bicentenario during 2019, lower interest costs from leases due to the modification of leased assets, partially offset by higher interest expense from the consolidation of Puerto Bahia.

Foreign Exchange Gain (Loss)

For the three months ended December 31, 2020, foreign exchange gain was $27.8 million, compared with a loss of $8.8 million in the same period of 2019, primarily due to the impact of the COP's revaluation against the USD on the translation of the debt consolidated from IVI during the fourth quarter 2020. For the year ended December 31, 2020, foreign exchange loss was comparable to the year ended December 31, 2019.

Other (Loss) Income, net

For the three months ended December 31, 2020, the Company recognized other losses of $3.0 million relating to the recognition of contingencies compared with $6.7 million in the same period of 2019. Other losses of $47.3 million for the year ended December 31, 2020 was primarily due to a non-cash charge of $42.8 resulting from the acquisition of Puerto Bahia compared with other income of $2.8 million in 2019 from fair value adjustments on the acquisition of CGX. For further information refer to Note 4 of the Annual Consolidated Financial Statements.

Reclassification of currency translation adjustments

For the year ended December 31, 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 associate investment.

(Loss) Gain on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Realized (loss) gain on risk management contracts(1)	(8,205)	(4,006)	13,628	(9,720)
Realized gain on unwinding of risk management contracts(1)	—	—	27,296	—
Unrealized gain (loss) on risk management contracts(2)	741	(10,333)	(6,481)	(5,722)
Total (loss) gain on risk management contracts	**(7,464)**	**(14,339)**	**34,443**	**(15,442)**

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

For the three months ended December 31, 2020, the realized loss on risk management contracts was $8.2 million, compared with $4.0 million in the same period of 2019, primarily as a result of higher volumes hedged with an average higher put premium paid in 2020.

For the year ended 2020 a $13.6 million realized gain on risk management contracts was the result of the significant drop in Brent benchmark price during the second quarter 2020 compared with a loss of $9.7 million in the previous year. In addition, in May 2020, the Company monetized crude oil hedges that were fully in-the-money and set to expire in the second half of 2020 for a realized gain of $27.3 million. The risk management positions were closed out and replaced with new instruments to provide additional protection closer to depressed oil price levels at that time. For further information refer to the risk management strategy described in the “Risk Management Contracts - Brent Crude Oil” section below.

The unrealized gain on risk management contracts for the three months ended December 31, 2020, was $0.7 million compared to $10.3 million loss in the same period of the previous year. For the years ended 2020 and 2019, there was a loss of $6.5 million and $5.7 million respectively, with such variances due to the changes in the benchmark forward prices of price, foreign exchange and interest rate over the contract periods.

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. The Company’s strategy aims to protect a minimum of 40% of the estimated production with a tactical approach, using a combination of instruments, capped and non-capped, to protect the revenue generation and cash position of the Company, while maximizing the upside. This diversification of instruments allows the Company to take a more dynamic approach to the management of its hedging portfolio. The forward hedging positions were also intended to support restarting production and protect the break-evens of previously shut-in fields. In 2020, the Company executed a risk management strategy using a variety of derivatives instruments, including 3 - ways and put spreads primarily to protect against downward oil price movements. The Company has also hedged a significant portion of expected production for the first half of 2021.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads $**	**Assets**	**Liabilities**
3-ways	January to June 2021	Brent	2,230,000	25.6/35.6/51.3	—	7.608
Put Spreads	January to June 2021	Brent	1,600,800	26.5/36.5	437	—
Total as at December 31, 2020					**437**	**7,608**

During 2021, the Company continued with its hedging program, adding the following positions subsequent to December 31, 2020, as follows:

Type of Instrument	Term	Benchmark	Notional Amount / Volume (bbl)	Avg. Strike Prices Put / Call; Call Spreads $
3-ways	July to December 2021	Brent	360,000	37/47/62.9
Put Spreads	July to December 2021	Brent	2,514,000	39.4/49.4
Total as at February 08, 2021			**2,874,000**	

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

As part of the acquisition of IVI, the Company consolidated a financial derivative to manage exposure to cash flow risks from the fluctuation of the interest rate expressed in LIBOR on the 2025 Puerto Bahia Debt. Refer to “Liquidity and Capital Resources” section on page 19 for further information. As at December 31, 2020, 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	January 2021 to June 2025	LIBOR + 180	135,100	3.9%	—	12,551
Total as at December 31, 2020					**—**	**12,551**

Income Tax Expense

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Current income tax recovery (expense)	9,541	(4,974)	480	(42,645)
Deferred income tax recovery (expense)	134,215	47,514	(33,764)	190,372
Total income tax recovery (expense)	**143,756**	**42,540**	**(33,284)**	**147,727**

The current income tax recovery for the fourth quarter of 2020 was $9.5 million, compared with an expense of $5.0 million in the same quarter of 2019, mainly from the reversal of a provision due to a voluntary settlement of tax uncertainties in Colombia. Deferred income tax recovery for the fourth quarter of 2020 was $134.2 million compared with a recovery of $47.5 million in the same quarter of 2019 due to higher recognition of deferred income tax arising from deductible temporary differences on undepreciated capital expenditures related to oil and gas properties.

The current income tax recovery for the year ended December 31, 2020 was $0.5 million, compared with an expense of $42.6 million in 2019 due to a charge recognized in 2019 from a reassessment of uncertain tax positions in Colombia. Deferred income tax expense for the year ended December 31, 2020 was $33.8 million compared to a recovery of $190.4 million in 2019, the change in deferred income taxes primarily resulted from the impact of lower oil prices on forecasts supporting deferred tax assets that had been recognized during 2019. For further information refer to Note 8 of the Annual Consolidated Financial Statements.

Net Income (Loss)

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Net income (loss) attributable to equity holders of the Company	48,636	69,408	(497,406)	294,287
Per share – basic ($)	0.50	0.71	(5.13)	3.01
Per share – diluted ($)	0.48	0.70	(5.13)	2.96

The Company reported a net income of $48.6 million for the fourth quarter of 2020 which included a total income tax recovery of $143.8 million, partially offset by an operating loss of $100.9 million, including a $99.1 million non-cash provision related to the Conciliation Agreement. Refer to the “Conciliation Agreement” section on page 22 for further details. This compared to a net income of $69.4 million in the fourth quarter of 2019, which included operating income of $45.0 million and a deferred income tax recovery of $47.5 million.

For the year ended December 31, 2020, the Company reported a net loss of $497.4 million, which included a loss from operations of $408.7 million (including a non-cash impairment charge of $141.4 million and a contingency provision from the

Conciliation Agreement of $118.7 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 net derecognition of deferred tax assets of $33.8 million. This compared to net income of $294.3 million in the same period of 2019, which included an income from operations of $141.4 million and a gain relating to the recognition of deferred income taxes of $190.4 million.

Capital Expenditures

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Maintenance and development drilling	8,543	58,198	56,451	196,522
Exploration activities [1]	8,566	47,700	32,344	96,995
Facilities and infrastructure	7,387	22,982	17,630	46,288
Other	375	3,572	1,678	6,114
Total capital expenditures	**24,871**	**132,452**	**108,103**	**345,919**

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

Capital expenditures for the three months and year ended December 31, 2020, were $24.9 million and $108.1 million, lower by 81% and 69%, respectively, compared with the same periods of 2019. The reduction was driven by a reduction of investing activities in line with the Company's program to manage the impact of the COVID-19 pandemic and lower oil price environment.

During the fourth quarter of 2020, the Company restarted development activities with the drilling of a well on the CPE-6 block, in addition to expenditures for major maintenance and facilities to maintain current production levels. During the fourth quarter of 2019, 18 development wells and three exploration wells were drilled. For the year ended December 31, 2020, the Company drilled 22 development wells and one exploration well, compared to 116 development wells and eight exploration wells in 2019.

Selected Quarterly Information

		2020				2019			
Operational and financial results		**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Oil production -Colombia	(bbl/d)	40,830	41,817	40,948	56,150	58,517	61,420	61,956	63,052
Oil production -Peru	(bbl/d)	—	—	—	5,385	10,164	6,510	9,975	2,271
Natural gas production -Colombia	(boe/d)	1,115	1,385	1,649	2,037	2,224	2,283	2,454	2,651
Production	(boe/d)	41,945	43,202	42,597	63,572	70,905	70,213	74,385	67,974
Oil and gas natural gas sales volumes	(boe/d)	44,577	40,445	35,963	64,333	65,809	54,378	66,105	59,968
Brent price	($/bbl)	45.26	43.34	33.39	50.82	62.42	62.03	68.47	63.83
Oil and gas sales	($/boe)	42.20	40.17	24.96	41.65	58.95	57.90	65.01	58.08
Realized (loss) gain on risk management contracts	($/boe)	(2.00)	(1.68)	12.19	2.65	(0.66)	(0.43)	(0.33)	(0.30)
Royalties	($/boe)	(0.47)	(0.23)	—	(1.18)	0.98	(2.41)	(2.40)	(1.74)
Diluent costs	($/boe)	(1.76)	(1.95)	(2.53)	(1.45)	(1.09)	(1.85)	(2.17)	(1.71)
Net sales realized price	($/boe)	37.97	36.31	34.62	41.67	56.22	53.21	60.11	54.33
Production costs	($/boe)	(13.46)	(8.97)	(9.03)	(12.48)	(13.76)	(11.60)	(11.17)	(11.40)
Transportation costs [1]	($/boe)	(10.93)	(9.89)	(11.28)	(12.44)	(12.84)	(12.00)	(12.49)	(12.70)
Operating netback [1]	($/boe)	13.58	17.45	14.31	16.75	29.62	29.61	36.45	30.23
Revenue	($M)	177,109	152,760	81,701	236,938	351,027	277,676	377,347	377,527
Net income (loss)	($M)	48,636	(90,473)	(67,760)	(387,809)	69,408	(49,117)	227,809	46,187
Per share – basic ($)	($)	0.50	(0.93)	(0.70)	(4.04)	0.71	(0.50)	2.32	0.47
Per share – diluted ($)	($)	0.48	(0.93)	(0.70)	(4.04)	0.70	(0.50)	2.29	0.47
General and administrative	($M)	19,851	10,539	9,716	15,015	22,897	18,476	18,207	16,492
Operating EBITDA [1]	($M)	35,639	52,113	37,608	46,982	137,052	124,586	179,665	144,855
Capital expenditures	($M)	24,871	2,905	15,651	64,676	132,452	70,761	73,487	69,219

1.For the first and second quarters of 2020 the cost of the BIC Ancillary Agreements and CLC Ancillary Agreements cancelled and unpaid were reclassified as Cost Under Terminated Pipeline Contracts. Refer to "Termination of Transportation Agreement" section on page 22 for further details.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, timing of cargo shipments, movement in Brent benchmark prices, and fluctuations in crude oil price differentials. In addition to decreases in the Company's production since 2019 due to natural declines on its mature fields, during the past three quarters of 2020 there was a significant reduction in production resulting from the voluntary shut-in of production from certain blocks due to the low global crude oil price environment and the impact of the COVID-19 pandemic, and reduction in transportation cost in 2020 due to the cessation of payments under the BIC Ancillary Agreements and CLC Ancillary Agreements. Refer to "Termination of Transportation Agreement" section on page 22 for further details.

Trends in the Company's net income (loss) are also impacted most significantly by the recognition and derecognition of deferred income taxes, DD&A, impairment charges of oil, gas and other assets, reclassification of currency translation adjustment on the acquisition of IVI, recognition of contingency provision from the Conciliation Agreement (refer to "Conciliation Agreement" section on page 22 for further details), and total gain (loss) from risk management contracts that fluctuate with changes in hedging strategies and crude oil benchmark forward prices.

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

Selected Annual Information

	As at and for the year ended December 31		
($M, except as noted)	**2020**	**2019**	**2018**
Revenue	648,508	1,383,577	1,320,485
Net (loss) income attributable to equity holders of the Company [1]	(497,406)	294,287	(259,083)
Per share – basic ($)	(5.13)	3.01	(2.59)
Per share – diluted ($)	(5.13)	2.96	(2.59)
Cash and cash equivalents	232,288	328,433	446,132
Total assets [1]	2,063,912	2,492,751	2,291,278
Total non-current liabilities [1]	567,241	639,460	578,822
Total liabilities [1]	1,299,080	1,222,717	1,184,090

1. Effective January 1, 2019, the Company adopted IFRS 16 on a modified retrospective basis and therefore 2018 and 2017 have not been restated and may not be comparable. Refer to Note 3b of the 2019 Annual Consolidated Financial Statements.

Revenue decreased to $0.65 billion in 2020 from $1.38 billion in 2019 and $1.32 billion in 2018. The revenue decrease was mainly due to the reduction in global crude oil prices, lower trading and less produced volumes sold.

Net loss for 2020 was $497.4 million, compared to a net income of $294.3 million in 2019 and a net loss $259.1 million for 2018, as a result of higher impairment charges, derecognition of deferred income tax assets, loss from the acquisition of IVI and the contingency provision from the Conciliation Agreement. Refer to "Conciliation Agreement" section on page 22 for further details.

Total assets decreased to $2.06 billion in 2020 from $2.49 billion and $2.29 billion, in 2019 and 2018, respectively, mainly as a result of impairment charges in oil and gas properties, intangible asset and reduction in cash and cash equivalents during 2020. Cash and cash equivalents decreased to $232.3 million in 2020, from $328.4 million and $446.1 million, in 2019 and 2018, respectively, as a result of a decrease in cash flows from operations due to the decline in oil price during 2020.

Midstream Activities

The Company has investments in certain infrastructure and midstream assets which includes storage and other facilities relating to the distribution and exportation of crude oil products in Colombia and the Company's investments in pipelines. 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 ODL JV (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]

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. As a result of the reclassification Bicentenario investment as an asset held for sale equity method was stopped during fourth quarter 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 94.12% through the conversion of certain debt into preferred shares with voting rights.

Prior to the acquisition of a controlling interest in Puerto Bahia on August 6, 2020, the Company had recognized $18.0 million as its share of losses from IVI compared with $10.4 million for the full year of 2019 mainly due to higher unrealized foreign exchange losses on the revaluation of Puerto Bahia's USD-denominated bank debt. Since the acquisition of control, Puerto Bahia has generated $13.8 million of segment operating income primarily from take-or-pay contracts in its liquid bulk storage terminal business. For the year ended December 31, 2019, the Company recorded an impairment charge of $36.6 million from the write-down of a long-term receivable from IVI.

ODL Pipeline

The Company holds a 59.93% interest in ODL JV, which has a 35% equity investment in Oleoducto de los Llanos Orientales (“**ODL”)**. ODL owns the Oleoducto de los Llanos pipeline, which connects the Rubiales, Quifa and Llanos-34 fields to the Monterrey Station or Cusiana Station in the Casanare Department.

For the year ended December 31, 2020, the Company recognized $42.2 million as its share of income from ODL which was $9.7 million lower than the same period of 2019 primarily due to a decrease in the transportation tariff in 2020 and the impact of foreign exchange fluctuations. During the year ended December 31, 2020, the Company received gross dividends of $42.0 million from ODL (2019: $52.8 million).

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.

For the year ended December 31, 2020, the Company recognized $19.4 million as its share of income from Bicentenario which was $24.0 million lower than the same period of 2019 primarily due to the impact of foreign exchange fluctuations. As at December 31, 2020, the discounted carrying value of dividends receivable from Bicentenario increased to $58.2 million ($62.0 million undiscounted) from $39.1 million ($45.7 million undiscounted) as at December 31, 2019.

On November 16, 2020, the Company, Bicentenario and Cenit Transporte y Logística de Hidrocarburos S.A.S. (“**Cenit**”) signed a Conciliation Agreement (refer to the “Conciliation Agreement” section on page 22 for further details), 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. On closing, the Company will transfer to Cenit its 43.03% equity interest in Bicentenario and any unpaid dividends. As a result, the Company reclassified its investment in Bicentenario of $66.2 million to assets held for sale in the fourth quarter of 2020. Closing is subject to Court approval of the terms of the Conciliation Agreement on or before June 30, 2021, or such later date as the parties may agree.

Midstream Segment Results

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

	Three months ended December 31		Year ended December 31	
($M)	**2020**	**2019**	**2020**	**2019**
Revenue	16,733	—	28,056	—
Operating Costs	(5,615)	—	(8,767)	—
General and administrative	(2,093)	—	(3,328)	—
Depletion, depreciation and amortization	(414)	—	(2,187)	—
Impairment	—	—	—	(36,627)
Segment income (loss) from operations	**8,611**	**—**	**13,774**	**(36,627)**
Share of Income from associates - ODL	10,730	10,574	42,214	51,899
Share of Income from associates - Bicentenario	2,694	9,560	19,356	43,356
Share of Income (loss) from associates - IVI	—	4,264	(18,023)	(10,423)
Segment income	**22,035**	**24,398**	**57,321**	**48,205**

Non-IFRS Measures

This MD&A contains the following terms that do not have standardized definitions in IFRS: “operating EBITDA,” “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 net tangible assets” and “consolidated adjusted EBITDA” in accordance with the terms of the Indenture (as defined on page 19). Refer to the “Liquidity and Capital Resources – Covenants” section on page 19.

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

Operating EBITDA

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

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

	Three months ended December 31		**Year ended December 31**	
($M)	**2020**	**2019**	**2020**	**2019**
Net income (loss)	48,636	69,408	(497,406)	294,287
Finance income	(6,665)	(3,162)	(19,529)	(20,244)
Finance expenses	18,778	17,438	58,421	65,492
Income tax (recovery) expense	(143,756)	(42,540)	33,284	(147,727)
Depletion, depreciation and amortization	51,637	89,753	258,867	376,010
(Reversal) impairment and others	(14,430)	3,389	137,513	63,580
Costs under terminated pipeline contracts	99,058	—	118,679	—
Reclassification of currency translation adjustments	—	—	23,956	—
Share-based compensation	1,181	(124)	3,960	2,907
Restructuring, severance and other costs	7,340	2,994	21,097	11,945
Share of income from associates	(13,422)	(24,398)	(43,545)	(84,832)
Foreign exchange (gain) loss	(27,840)	8,812	7,742	10,264
Unrealized (gain) loss on risk management contracts	(741)	10,333	6,481	5,722
Other loss (income), net	3,043	6,680	47,328	(2,758)
Non-controlling interests	12,820	(1,531)	15,494	11,512
Operating EBITDA	**35,639**	**137,052**	**172,342**	**586,158**

Net Sales

Net sales is a non-IFRS subtotal that adjusts revenue to include realized gains and losses from risk management contracts while removing the cost of dilution activities. 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 is helpful to understand the Company’s sales performance based on the net realized proceeds from production net of diluent, the cost of which is partially recovered when the blended product is sold. Net sales excludes sales from port services, as it is not considered part of the oil & gas segment, and sales and purchases of oil and gas for trading, as the gross margins from these activities are not considered significant or material to the Company’s operations. 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 trading activities and Midstream segment from its 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.

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

	Three months ended December 31		Year ended December 31	
	2020	2019	2020	2019
Net sales ($M)	155,692	340,431	648,085	1,261,517
Sales volumes (D&P) - (boe)	4,101,084	6,054,428	16,948,728	22,469,765
Net sales realized price ($/boe)	37.97	56.22	38.24	56.15

Production cost per boe is calculated using production cost divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2020	2019	2020	2019
Production costs ($M)	51,930	89,789	194,770	310,084
Production (boe)	3,858,940	6,523,260	17,494,800	25,869,375
Production costs ($/boe)	13.46	13.76	11.13	11.99

Transportation cost per boe is calculated using transportation cost divided by net production after royalties. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
	2020	2019	2020	2019
Transportation costs ($M)	39,354	76,428	182,597	295,554
Net production (boe)	3,599,684	5,951,480	16,206,480	23,632,290
Transportation costs ($/boe)	10.93	12.84	11.27	12.51

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 cash attributable to the Unrestricted Subsidiaries.

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

	As at December 31
($M)	**2020**
Long-term debt	335,788
Total lease liabilities [1]	19,042
Risk management liabilities, net[2]	7,171
Consolidated Total Indebtedness excluding 2025 Puerto Bahia Debt	362,001
(-) Cash and Cash Equivalents [3]	(215,023)
(=) Net Debt excluding 2025 Puerto Bahia Debt	146,978

1. Excludes $0.3 million of lease liabilities attributable to the Unrestricted Subsidiaries.
2. Excludes $12.6 million of risk management liabilities attributable to the Unrestricted Subsidiaries.
3. Excludes $17.3 million of cash attributable to the Unrestricted Subsidiaries.

6. LIQUIDITY AND CAPITAL RESOURCES

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

- 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 dividends and share repurchases.

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

As at December 31, 2020, the Company had a total cash balance of $401.2 million (including $168.9 million in restricted cash), which is $54.6 million lower than at December 31, 2019. For the year ended December 31, 2020, the Company generated $226.8 million in operating cash flows which was used to fund cash outflows of $178.5 million for capital expenditures and other investing activities (including $3.0 million for the acquisition of IVI). Financing outflows for the year ended December 31, 2020 included $24.5 million in lease payments, $42.2 million of interest and other financing charges, $20.5 million of dividends paid to equity holders, $20.0 million of 2025 Puerto Bahia Debt payments and $10.1 million to repurchase common shares. Additionally, the Company consolidated $183.1 million of 2025 Puerto Bahia Debt as a result of the acquisition of IVI (classified as a current liability) which reduced the consolidated working capital position to a deficit of $111.7 million compared with a surplus of $71.4 million at year-end. For further information of the 2025 Puerto Bahia Debt refer to "Puerto Bahia Secured Syndicated Credit Loan" section below and Note 20 of the Annual Consolidated Financial Statements.

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As at December 31, 2020, 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 are expected to be released as the related processes are closed. As at December 31, 2020, total restricted cash of $168.9 million, increased by $41.6 million from December 31, 2019 primarily due to Puerto Bahia consolidated restricted cash of $17.0 million and additional collateral for letters of credit issued as a guarantee for abandonment obligations, partially offset by the impact from foreign exchange.

In response to the decline in global oil prices resulting from the sustained impacts of the COVID-19 pandemic and related supply-demand market imbalances, the Company previously announced that it had taken steps to manage its liquidity and balance sheet through significant curtailments in the 2020 capital program for drilling and completion activities, voluntarily shutting-in uneconomic production and reductions to operating costs, transportation costs and G&A through cancellation of non-essential services, deferral of tariff payments, and reduction of head-count.

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 in the current oil price environment. 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 26.

Unsecured Notes

The Company's long-term borrowing consists of $350.0 million of unsecured notes issued on June 25, 2018 (the "**Unsecured Notes**"). The Unsecured Notes bear interest at a rate of 9.7% per year, payable semi-annually in arrears on June 25 and December 25 of each year. The Unsecured Notes will mature on June 25, 2023, unless earlier redeemed or repurchased.

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 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 Unsecured Notes. As at December 31, 2020, the 2025 Puerto Bahia Debt outstanding amount is $183.1 million.

As part of the agreements for the bank loan to fund the construction of Puerto Bahia, the Company entered into an 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.

On December 11, 2020, the Company disbursed $8.0 million to Puerto Bahia bearing interest of 14%. As of December 31, 2020, the Company has advanced a total of $73.9 million of ECA Loans under the ECA. During fourth quarter 2020, $41.3 million of ECA Loans were capitalized into preferred shares of Puerto Bahia (refer to the "Midstream Activities" section on page 15 for further details). As a result of the acquisition of IVI, pre-existing relationships between the Company and IVI are considered as intercompany transactions that are eliminated in the Annual Consolidated Financial Statements.

Letters of Credit

The Company has various uncommitted bilateral letter of credit lines (the "**Uncommitted LCs**"). As of December 31, 2020, the Company had $52.9 million of issued and outstanding Uncommitted LCs for exploratory commitments and abandonment funds in Colombia and Ecuador. The lenders under the Uncommitted LCs receive a fee equal to 3% per annum.

In addition to the Uncommitted LCs, as at December 31, 2020, the Company has outstanding letters of credit of $4.0 million under a master agreement with Banco BTG Pactual S.A. ("**BTG**"). Under the terms of this agreement, BTG has the right to demand the return and cancellation of the letters of credit, or require the Company to deposit an equivalent of cash amount if it breaches certain covenants, including receiving a credit rating downgrade two notches or more by any rating agency and financial ratios. As at March 3, 2021, the Company is in compliance with covenants from this agreement.

Unsecured Notes Covenants

The 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. Under the terms of the Unsecured Notes, the Company (excluding the Unrestricted Subsidiaries) may, among other things, incur indebtedness provided that the consolidated debt to consolidated adjusted EBITDA ratio[(1)] is less than or equal to 3.0:1.0 and the consolidated fixed charge ratio[(2)] is greater than or equal to 2.5:1.0. In the event that these financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $100.0 million and 10% of consolidated net tangible assets[(3)]. The Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at December 31, 2020, the Company is in compliance with all such covenants.

As of December 31, 2020, and pursuant to requirements under the Indenture, the Company reports consolidated net tangible assets of $1,187,466,000 consolidated total indebtedness of $362,001,000 consolidated adjusted EBITDA of $179,132,000 and consolidated interest expense of $35,005,000.

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 17.
    b. Consolidated adjusted EBITDA is defined as the consolidated net income (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense and abandonment costs; after excluding the impact of the Unrestricted Subsidiaries.
2. Consolidated fixed charge ratio is the consolidated adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period as defined in the Indenture.
3. Consolidated net tangible assets is defined in the Indenture as the net amount of the Company's total assets less intangible assets and current liabilities, after excluding the impact of the Unrestricted Subsidiaries.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at December 31, 2020, undiscounted by calendar year, are presented below:

As at December 31, 2020 ($M)	2021	2022	2023	2024	2025	2025 and Beyond	Total
Financial obligations							
Long-term debt, including interest payments	33,958	33,958	366,982	—	—	—	434,898
Lease liabilities	12,234	5,936	3,250	68	56	—	21,544
2025 Puerto Bahía Debt and interest (1)	48,897	47,259	50,075	47,700	13,600	—	207,531
Total financial obligations	**95,089**	**87,153**	**420,307**	**47,768**	**13,656**	**—**	**663,973**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	$ 69,640	$ 69,640	$ 69,640	$ 69,640	$ 34,793	$ —	$ 313,353
ODL agreements (2)	7,888	—	—	—	—	—	7,888
Other transportation agreements	8,501	—	—	—	—	—	8,501
Exploration commitments							
Minimum work commitments (3)	74,634	118,211	35,244	3,600	—	—	231,689
Other commitments							
Operating purchases, leases and community obligations	23,267	8,897	8,575	7,707	7,681	321	56,448
Total Commitments	**$ 183,930**	**$ 196,748**	**$ 113,459**	**$ 80,947**	**$ 42,474**	**$ 321**	**$ 617,879**

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 amounts for the new ODL transportation contract until June 30, 2021. If the Conciliation Agreement closes, additional commitments will extend until 2024. Refer to "Conciliation Agreement" for further details on page 22.
3. Includes minimum work commitments relating to exploration activities in Colombia and Ecuador only 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 as described below.

Guyana Exploration

As of December 31, 2020, the Company, through its 73.85% interest in CGX, has exploration work commitments under its Petroleum Prospecting Licenses ("**PPL**") for certain blocks in Guyana, as follows:

- In accordance with the Corentyne PPL, which is currently in phase one of the second renewal period, one (1) exploration well must be drilled by November 27, 2021.
- In accordance with the Demerara PPL, which is currently in phase one of the second renewal period, one (1) exploration well must be drilled by February 11, 2022.
- In accordance with the Berbice PPL, which is currently in phase one of the second renewal period, the Company shall complete a seismic program, including all associated processing and interpretations, by August 12, 2021.

Other Guarantees and Pledges

The Company has a pledge agreement with Repsol Colombia Oil & Gas Ltd. ("**RCOG**") pursuant to which it granted a pledge over the production from the CPE-6 block as a guarantee for the variable payments, up to a maximum of $48.0 million, which are calculated and contingent on production from CPE-6 block. This relates to the Company's acquisition of RCOG's 50% working interest in this block. As at December 31, 2020, the Company has paid a total of $2.8 million of such amounts under the agreement.

On April 29, 2020, the Company entered into a pledge agreement with Ocensa pursuant to which the Company granted a pledge over the crude oil delivered to the Ocensa pipeline to secure payment of ship or pay obligations under the Ocensa P-135 ship-or-pay agreement. The pledge agreement will automatically terminate if the Company subsequently meets certain credit conditions set forth in the ship-or-pay agreement.

Contingencies

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

Termination of Transportation Agreements

On July 12, 2018, the Company exercised contractual rights to terminate (a) three transportation contracts (the "**BIC Transportation Agreements**") with Bicentenario to ship oil through the BIC Pipeline which operates between Araguaney and Banadia where it connects to the CLC Pipeline because service had not been provided for more than six consecutive months, and (b) three related transportation agreements (the "**CLC Transportation Agreements**") with Cenit to ship oil through the CLC Pipeline because service had not been provided for more than 180 consecutive calendar days.

On December 3, 2018, Cenit, and on January 28, 2019, Bicentenario, commenced separate arbitration proceedings against the Company before the Centre for Arbitration and Conciliation of the Bogota Chamber of Commerce (the "**Bogota Arbitration Centre**") disputing the validity of the terminations (the “Bicentenario Arbitration” and “CLC Arbitration”, respectively).

The Company believes that it was fully entitled to terminate both the BIC Transportation Agreements and the CLC Transportation Agreement. In addition to vigorously defending itself in the Bicentenario Arbitration and the CLC Arbitration, the Company has filed counterclaims against Cenit and Bicentenario. In the counterclaims, the relief claimed against Bicentenario includes payment of $486.5 million plus interest for letters of credit improperly drawn, service prepayments, credits and unpaid dividends declared in 2018, and the relief claimed from Cenit includes release of $32.1 of restricted cash in connection with the dispute concerning the tariff rate for the CLC Pipeline applicable to service payments made before the termination of the CLC Transportation Agreements on July 12, 2018.

The Company and certain of its affiliates also commenced a separate arbitration proceeding against Bicentenario and Cenit on December 3, 2019, before the Bogota Arbitration Centre as an international arbitration (the “**International Arbitration**”) seeking relief from Bicentenario and Cenit on the basis that, amongst among other things, those contracts were validly terminated. In addition to the relief claimed in the Bicentenario Arbitration and CLC Arbitration, the relief claimed in the International Arbitration includes claims for recovery of various rights as a shareholder of Bicentenario and for the termination of (a) three transportation ancillary contracts (the "**BIC Ancillary Agreements**") with Bicentenario for the use of ancillary facilities related to the BIC Pipeline, and (b) seven transportation ancillary contracts (the "**CLC Ancillary Agreements**") with Cenit related to the CLC Pipeline and the BIC Pipeline for offloading and maritime facilities (which were the subject of termination), and the Monterrey-Araguaney Pipeline.

During the first quarter of 2020, the Company asserted rights to stop making payments under the BIC Ancillary Agreements and the CLC Ancillary Agreements. Both Bicentenario and Cenit dispute the grounds for the termination of these contracts and the cessation of payment, but they have not filed any formal claim yet over this specific dispute.

In addition, on December 3, 2019, Bicentenario commenced arbitration proceedings before the Bogota Arbitration Centre against various shareholders of Bicentenario including the Company (the “**AMI Arbitration**”), claiming that as a result of the loss of revenue resulting from the cessation of payments pursuant to various transportation contracts including the BIC Transportation Agreements, the shareholders are obliged to contribute additional funds to Bicentenario to cover debt service payments and other amounts. On October 22, 2020, Bicentenario withdrew the AMI Arbitration proceedings and gave notice that it would make similar claims in a counterclaim under the International Arbitration initiated by the Company.

The Bicentenario Arbitration and CLC Arbitration have completed the initial pleadings stage. At the request of the parties, the arbitration panels have suspended both the proceedings until March 31, 2021, pending the progress of tribunal approval of the Conciliation Agreement. The International Arbitration continues to progress with the pleading phase at this time.

As of December 31, 2020, the amount of tariffs claimed by Cenit under the CLC Transportation Agreements would be approximately $147.1 million plus interest, and would be approximately $70.3 million per annum, subject to tariff adjustments from time to time, until 2028. As of December 31, 2020, the aggregate amount of monthly service payments claimed by Bicentenario under the BIC Transportation Agreements would be $189.1 million (net of credits note and stand by letter of credit) plus interest, and would be approximately $130.6 million per annum, subject to tariff adjustments from time to time, until 2024. As of December 31, 2020, the Company has rejected invoices for $22.4 million relating to the BIC Ancillary Agreements and CLC Ancillary Agreements.

For further information on these claims, see “Note 28 - Commitments and Contingencies” of the Annual Consolidated 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 a binding settlement which, upon completion and approval by the competent Colombian court, will resolve all the disputes pending among them, related to BIC Pipeline and CLC Pipeline, and will terminate all the pending arbitration proceedings related to such disputes, including the Bicentenario Arbitration, CLC Arbitration and International Arbitration.

The parties consider that this transaction eliminates any uncertainty related to the potential outcomes of the disputes, thus protecting the interests of all the parties and those of their stakeholders. The settlement arrangement includes a full and final mutual release upon closing of all present and future amounts claimed by all parties in respect of the terminated transportation contracts for both the CLC Pipeline and the BIC Pipeline, and also in respect of certain related contracts involving the liabilities which are recorded by Frontera as Cost Under Terminated Pipeline Contracts.

The Conciliation Agreement does not include any cash payments between the parties, except for Frontera's release of its interests in a trust fund (restricted cash) of approximately $32.1 million as of December 31, 2020 including interest, created as collateral for one of the claims. Upon completion of the settlement, the Company will transfer to Cenit its 43.03% interest in Bicentenario, any related outstanding Bicentenario dividends, and the BIC Pipeline line fill. The claims released by Frontera include recovery of the letters of credit drawn by Bicentenario in 2018 and all other claims that have been asserted by Frontera against Bicentenario.

In connection with the closing of the settlement, the Company will also enter into new transportation contracts with Cenit and Bicentenario and has already entered into a new transportation contract with ODL which it can terminate if the settlement does not close. See further detail below under “New Transportation Contracts”.

The arrangement is conditional upon approval of the Conciliation Agreement under Colombian law which requires an opinion to be issued by the Office of the Attorney General of Colombia (Procuraduría General de la Nación) and approval of the Administrative Tribunal of Cundinamarca, the final appeals court with competence regarding the Conciliation Agreement to which state-owned companies are a party.

The Conciliation Agreement provides that if such approvals are not obtained by June 30, 2021 or such later date as may be agreed, then either party will become entitled to terminate the Conciliation Agreement, and that the legal rights of the parties with respect to the disputes are not prejudiced unless and until the required approvals are obtained and the Conciliation Agreement is closed. There can be no assurance that the required approvals will be received on a timely basis or at all.

As a result of the Conciliation Agreement, the Company recognized $96.3 million as Cost Under Terminated Pipeline Contracts in the income statement, which represents the fair value of the assets to be transferred of $148.6 million, offset by previous contingent liabilities related with the claim in respect of the terminated transportation contracts of $52.3 million.

At the time of closing the transaction, the Company will recognize a non-cash loss reclassification of CTA from other equity reserves to Statements of (Loss) Income. As of December 31, 2020, the Company has recognized a CTA balance of $105.3 million within equity. The CTA loss primarily related to historical functional currency COP to USD presentation currency translation differences on Bicentenario, as an associate investment.

The Company classified the investment in associate of Bicentenario related to the Conciliation Agreement as assets held for sale according to IFRS 5. For further detail see “Note 14 - Assets held for sale” of the 2020 Annual Consolidated Financial Statements.

New Transportation Contracts

The new ODL transportation contract entered into in connection with the Conciliation Agreement provides for a ship or pay commitment of 10,000 bbls/day for approximately 3.8 years at a current tariff of $4.0/bbl. The ODL pipeline is regularly used by the Company to transport crude oil from its heavy oil district which produces sufficient volumes to comply with the new obligations. The contract is expected to come into effect during the second quarter of 2021, and is subject to termination by the Company if the Conciliation Agreement does not close.

The new transportation contracts with Cenit and Bicentenario for use of the CLC Pipeline and BIC Pipeline (and certain related facilities) will become effective within a six-month period as of the closing of the Conciliation Agreement. The new take or pay commitment is projected to be approximately 3,900 bbls/day, subject to adjustments in changes in the oil price and Colombia/ U.S. exchange rates between now and closing, for a term of five years at a current tariff of $11.5/bbl. Frontera will not have to make payments under the new transportation contracts for oil that is required to be shipped on alternative pipeline systems due to the unavailability of the CLC Pipeline and BIC Pipeline. Frontera will be able to use the CLC Pipeline or the BIC Pipeline for the transportation of oil to Coveñas as an alternative to the use of the Ocensa pipeline.

High-Price Clause

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

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

Ecopetrol - Rubiales Field Disagreement

The Company has been involved in negotiations with Ecopetrol with respect to disagreements on wind-down costs and expenses, as well as inventory, in connection with the expiration of the Rubiales and Piriri exploration and production contracts in June 2016. On November 22, 2018, the Company filed a lawsuit against Ecopetrol before the Administrative Tribunal of Cundinamarca claiming it is owed $24.9 million. The Company is aware that Ecopetrol has also initiated a legal proceeding claiming approximately $52.2 million. The Company has not yet been served with such claim.

Tax reviews

The Company operates in various jurisdictions and is subject to assessments by tax authorities in each of those jurisdictions, which can be complex and based on interpretations. The Company is currently in discussions with tax authorities for various assessments with respect to certain income tax deductions relating to exportation expenditures, transportation costs, VAT credits, municipal taxes, and other expenses. As at December 31, 2020, the Company has assessed a possible tax exposure of $253.1 million (2019: $224.3 million) relating to these assessment for taxes, interest and penalties and recorded a provision of $1.2 million for the potential liability relating to these matters. In November 2020, as part of a tax settlement program, the Company voluntarily settled $23.0 million of previously assessed income tax, for a total payment of $12.7 million.

7. OUTSTANDING SHARE DATA

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

	Number
Common shares	97,466,224
Deferred share units ("**DSUs**") (1)	595,359
Restricted share units ("**RSUs**") (2)	2,862,683

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 2019 and 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 a normal course issuer bid ("**NCIB**") as described below. The Board will continue to evaluate the dividend policy considering market conditions.

Declaration Date	Record Date	Payment Date	Dividend (C$/ Share)	Dividends Amount ($M)	Number of DRIP Shares (1)
December 6, 2018	January 3, 2019	January 17, 2019	0.330	24,464	625,923
March 13, 2019	April 2, 2019	April 16, 2019	0.165	12,144	2,393
May 30, 2019	July 3, 2019	July 17, 2019	0.205	15,351	244
August 1, 2019	August 9, 2019	August 23, 2019	0.535	39,371	1,887
August 1, 2019	October 2, 2019	October 16, 2019	0.205	15,106	497
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			1.850	135,527	2,784,577

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

Over a 12-month period between October 18, 2019 and October 17, 2020, the Company had a NCIB through the TSX, allowing the Company to purchase for cancellation up to 6,532,400 of its Common Shares. During the fourth quarter of 2020, the Company did not purchase Common Shares under the NCIB. During the twelve month term of the NCIB ended October 17, 2020, the Company purchased and cancelled a total of 2,941,128 Common Shares.

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

	Year ended December 31,	
	2020	2019
Number of common shares repurchased	1,392,314	2,642,834
Total amount of common shares repurchased ($M)	10,075	21,752
Weighted-average price per share ($)	7.24	8.23

The Company intends to file with the TSX a notice of intention to commence a NCIB, for its Common Shares. If accepted by the TSX, the Company would be permitted under the NCIB to purchase , during a 12-month period, up to 5,197,612 Common Shares, representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules). The NCIB will be made in accordance with the rules of the TSX through the facilities of the TSX or alternative trading systems, if eligible. The Company believes that, from time to time, the market price of its Common Shares may not fully reflect the underlying value of its business and future prospects and financial position. In such circumstances, the Company may purchase for cancellation outstanding Common Shares, thereby benefitting all shareholders by increasing the underlying value of the remaining Common Shares. At the present time, the Board believes that an NCIB is a more effective way to deliver value to shareholders when compared to cash dividends.

8. RELATED-PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances outstanding and commitments with related parties, as at December 31, 2020 and 2019, and for the three months and year ended December 31, 2020 and 2019, respectively:

($M)		Accounts Receivable (1)	Accounts Payable and Lease Obligation	Commitments (2)	Cash Advance (1) (3)	Long-term Receivable (1) (3)	Interest Receivable (1) (3)
ODL	2020	465	7,821	7,888	—	—	—
	2019	—	4,181	30,125	—	—	—
Bicentenario (4)	2020	70,761	—	—	87,278	—	—
	2019	9,677	—	36,539	87,278	45,732	—
IVI (5)	2019	—	31,193	52,238	17,741	151,452	52,267

		Three months ended December 31		Year ended December 31	
($M)		Purchases / Services	Interest Income (1)	Purchases / Services	Interest Income (1)
ODL	2020	7,784	—	35,903	—
	2019	11,306	—	49,356	—
Bicentenario (4)	2020	—	—	1,427	—
	2019	1,441	—	6,557	—
IVI (5)	2020	—	—	22,479	10,558
	2019	8,280	4,131	32,347	15,109
CGX Energy Inc. (6)	2020	—	—	—	—
	2019	—	—	—	363

1. Amounts presented based on contractual payment obligations undiscounted and prior to impairments.
2. Refer to the "Commitments and Contractual Obligations" section on page 21.
3. Items included as Other Assets in the Annual Consolidated Financial Statement of Financial Position.
4. On November 16, 2020, the Company signed a Conciliation Agreement, and as result the Company reclassified the dividends receivable from long-term receivable to accounts receivable.
5. Balances shown reflect transactions before the Company acquired control of IVI on August 6, 2020, refer to Note 4 of 2020 Annual Consolidated Financial Statements. Prior to the acquisition, the Company had disclosed the commitments with Puerto Bahia related to its take-or-pay agreement.
6. Transactions before the Company acquired control of CGX on March 13, 2019.

For further information refer to note 26 of the Annual Consolidated Financial Statements.

9. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives. 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 mitigates these risks to an acceptable level. In addition, we continuously monitor our risk profile as well as industry best practices.

The Company attempts to mitigate its strategic risks to an acceptable level through a variety of policies, systems and processes. A summary of certain significant risks that are reasonably likely to affect the financial performance of the Company are set forth below. For a comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the AIF and Annual Consolidated Financial Statements as of December 31, 2020, copies of which are available on SEDAR at www.sedar.com.

Significant Risk Factors

Production

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

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

Liquidity/Financial

The Company is exposed to normal financial risks inherent in the oil and natural gas industry, including liquidity risk, commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company's principal liquidity and capital resource requirements are capital expenditure for exploration and development, operating expenses, debt services and shareholder returns (such as dividends). The Company funds these requirements through current cash and working capital balances which are carefully managed to ensure that operational needs and other financial obligations are met. For further information on liquidity and capital risk mitigation see section "Liquidity and Capital Resources" on page 19.

The Company also continuously monitors opportunities to use financial instruments such as derivatives to manage exposure to fluctuations in commodity prices and interest rate. For further information see the sections "Risk Management Contracts - Brent Crude Oil" section on page 12 and "Risk Management Contracts - Interest Rate Swap (2025 Puerto Bahia Debt)" section on page 13.

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

Health, Safety and Environmental

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

Exploration, New Business and Reserves Growth

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

Information Security

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

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

Political Risks

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

COVID-19 Pandemic

In March 2020, the World Health Organization declared the outbreak of COVID-19 as a global pandemic. The COVID-19 pandemic has had and is expected to continue to have a negative impact on the Company's financial condition, results of operations, and cash flows.

The impact of the COVID-19 pandemic and the related uncertainty regarding the price, of and demand for, oil and natural gas products continues to evolve. The risk of a resurgence or additional variant strains remains high and delays in vaccine rollouts could result in continued fluctuations in the price of oil and natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events have had, and could continue to have, a material adverse effect on the Company's business, financial condition and results of operations. Even after the COVID-19 pandemic has subsided, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic's global economic impact. 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.

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

10. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

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

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

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

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

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

11. INTERNAL CONTROL

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

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations. Additionally, in 2020, Management has been monitoring the impacts of COVID-19 on the Company's control environment. These impacts include remote work environment, oil price environment and budget restrictions, cyber threats, IT help desk services response time, health and safety, impairment and going concern. While there were no changes made to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting, the Company will continue to monitor and mitigate the risks associated with any changes to its control environment. in response to COVID-19 pandemic.

Management has evaluated the effectiveness of the Company's ICFR as at December 31, 2020.

Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at December 31, 2020.

There have been no changes in the Company's ICFR during the quarter ended December 31, 2020, 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 annual filings are being prepared, and that information required to be disclosed by the Company in its annual filings, interim filings and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Based on Management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and its Chief Financial Officer, concluded that the Company's DC&P were effective as at December 31, 2020.

12. 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. Under this contract, the volumes produced are owned by Perupetro and the Company is entitled to in-kind payments on production, which can range from 44% to 84% of production on the block.

This percentage is determined by the "R" Factor, which is related to income and expenses in accordance with the service contract. The Company reports 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 (in boe/d)				
Producing blocks in Colombia	**Q4 2020**	**Q3 2020**	**Q4 2019**	**FY 2020**	**FY 2019**
Heavy oil	19,694	20,443	29,778	22,553	29,321
Light and medium oil	18,318	18,387	24,155	19,064	26,896
Natural gas	1,115	1,385	2,224	1,545	2,401
Net production Colombia	**39,127**	**40,215**	**56,157**	**43,162**	**58,618**
Producing blocks in Peru					
Light and medium oil	—	—	8,533	1,118	6,128
Net production Peru	**—**	**—**	**8,533**	**1,118**	**6,128**
Total net production	**39,127**	**40,215**	**64,690**	**44,280**	**64,746**

Peru Royalties - Block 192 Contract

Block 192, located in the Northern Marañon Basin of Peru, was operated by the Company pursuant to a service contract awarded by Perupetro. The service contract expired as per its terms on February 5, 2021 and the Company is no longer operating on the block.

As at December 31, 2020, the Company has received in-kind payments for its services equivalent to 83% of the production from the block, with the balance being retained by Perupetro. Due to the lack of production in Peru during the fourth quarter of 2020, Perupetro did not retain any in-kind volumes compared with 1,631 bbl/d in the fourth quarter of 2019. For the year ended December 31, 2020, Perupetro retained in-kind volumes averaging 221 bbl/d compared with 1,122 bbl/d in 2019 .

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 9.

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.

Reserves Information

This MD&A includes non-standardized measures. Readers are cautioned that these measures, such as reserve life index and reserves replacement ratio, should not be construed as alternative measures of financial performance. Such measures have been included to provide readers with additional means to evaluate the Company's performance but these non-standardized measures are not reliable indicators of the Company's future performance and therefore must not be relied upon unduly. The Company's method of calculating these measures may differ from other companies and, accordingly, they may not be comparable to similar measures used by other companies.

Abbreviations

The following abbreviations are frequently used in the Company’s MD&A.

bbl	Oil barrels	**PAP**	High-price clause participation
bbl/d	Barrels of oil per day	**Q**	Quarter
boe	Barrels of oil equivalent	**USD**	United States dollars
boe/d	Barrels of oil equivalent per day	**WTI**	West Texas Intermediate
COP	Colombian pesos	**$**	U.S. dollars
C$	Canadian dollars	**$M**	Thousand U.S. dollars
D&P	Development and producing	**$MM**	Million U.S. dollars
E&E	Exploration and evaluation	**P1**	Proved reserves
MMbbl	Millions of oil barrels	**P2**	Probable reserves
MMboe	Millions of barrels of oil equivalent	**P1**	Proved reserves + Probable reserves
Mcf	Thousand cubic feet	**2P**	Proved reserves + Probable reserves