MANAGEMENT DISCUSSION & ANALYSIS

November 6, 2019
For the three and nine months ended September 30, 2019

*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 1188 West Georgia Street, Suite 650, Vancouver, British Columbia, Canada, V6E 4A2.*

Legal Notice – Forward-Looking Information and Statements

*This Management Discussion and Analysis ("**MD&A**") is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Condensed Consolidated Financial Statements and related notes for the three and nine months ended September 30, 2019 and 2018 ("**Interim Financial Statements**"). 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" on page 16.*

Certain statements in this MD&A constitute 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 production levels, operating EBITDA, capital expenditures (including plans and projects related to drilling, exploration activities, facilities and infrastructure) and obtaining regulatory approvals, involve known and unknown risks, uncertainties and other factors that may cause the actual levels of production, costs and results to be materially different from the estimated levels expressed or implied by such forward-looking statements.

*The Company believes the expectations reflected in these forward-looking statements are reasonable, but the Company 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 publicly 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 heading "Forward-Looking Information" in the Company's Annual Information Form ("**AIF**") for the year ended December 31, 2018, dated March 13, 2019. 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 so results may not be as anticipated, estimated or intended.*

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

Additional information with respect to the Company, including the Company's quarterly and annual financial statements and the 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.

1. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q3 2019	Q2 2019	Q3 2018	Nine months ended September 30 2019	Nine months ended September 30 2018
Operational Results						
Oil production	(bbl/d)	67,930	71,931	62,271	68,405	66,234
Natural gas production	(boe/d)	2,283	2,454	4,122	2,461	4,498
Production (1)	(boe/d) (2)	70,213	74,385	66,393	70,866	70,732
Oil and gas sales and other revenue	($/boe)	57.90	65.01	68.02	60.56	66.04
Realized loss on risk management contracts	($/boe)	(0.43)	(0.33)	(10.02)	(0.35)	(10.13)
Royalties	($/boe)	(2.41)	(2.40)	(2.83)	(2.18)	(2.28)
Diluent costs	($/boe)	(1.85)	(2.17)	(1.89)	(1.92)	(1.83)
Net sales realized price (3)	($/boe)	53.21	60.11	53.28	56.11	51.80
Production costs (4)	($/boe)	(11.60)	(11.17)	(13.84)	(11.39)	(12.43)
Transportation costs (5)	($/boe)	(12.00)	(12.49)	(13.77)	(12.39)	(12.73)
Operating netback (6)	($/boe)	29.61	36.45	25.67	32.33	26.64
Financial Results						
Oil and gas sales and other revenue	($M)	289,641	391,049	382,189	994,149	1,090,283
Realized loss on risk management contracts	($M)	(2,135)	(1,986)	(56,297)	(5,714)	(167,303)
Royalties	($M)	(12,051)	(14,439)	(15,902)	(35,866)	(37,624)
Diluent costs	($M)	(9,238)	(13,028)	(10,647)	(31,483)	(30,253)
Net sales (6)	($M)	266,217	361,596	299,343	921,086	855,103
Net (loss) income (7)	($M)	(49,117)	227,809	45,105	224,879	(142,452)
Per share – basic	($)	(0.50)	2.32	0.45	2.29	(1.42)
Per share – diluted	($)	(0.50)	2.29	0.45	2.26	(1.42)
General and administrative	($M)	18,476	18,207	22,962	53,175	71,183
Operating EBITDA (6)	($M)	126,155	181,159	93,455	452,169	304,110
Cash provided by operating activities	($M)	113,042	176,118	177,627	361,235	315,497
Capital expenditures (8)	($M)	70,761	73,487	124,029	213,467	289,683
Cash and cash equivalents – unrestricted	($M)	313,957	353,911	586,578	313,957	586,578
Restricted cash short and long-term	($M)	128,336	131,723	199,906	128,336	199,906
Total cash	($M)	442,293	485,634	786,484	442,293	786,484
Total debt and lease liabilities (9)	($M)	404,815	412,158	352,330	404,815	352,330

1. Represents working interest production before royalties and total volumes produced from service contracts. Refer to the “Further Disclosures” section on page 23.
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 16. 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 sales from exploration and evaluation (“**E&E**”) assets.
9. Effective January 1, 2019, the Company adopted IFRS 16 - Leases (“**IFRS 16**”), which had a significant impact on reported results for 2019. The standard was adopted on a modified retrospective basis and therefore prior year information has not been restated and may not be comparable. Refer to Note 2 of the Interim Financial Statements.

Highlights for the Third Quarter of 2019

Financial and Operational Results

- Production averaged 70,213 boe/d during the third quarter of 2019, compared to 74,385 boe/d in the second quarter of 2019 and 66,393 boe/d in the third quarter of 2018, reflecting stable production from Colombia and lower production from Peru due to a force majeure event on the Norperuano pipeline.
- Oil and gas sales and other revenue were $289.6 million in the third quarter of 2019, compared to $391.0 million in the previous quarter due to lower realized prices, an inventory buildup and timing of cargo shipments.
- Cash provided by operating activities was $113.0 million in the third quarter of 2019, compared to $177.6 million in the same prior year quarter, contributing to a total cash position of $442.3 million, including $128.3 million of restricted cash, as at September 30, 2019.
- Net loss for the third quarter of 2019 was $49.1 million ($0.50/share) compared with a net income of $45.1 million ($0.45/share) in the third quarter of 2018.
- Operating EBITDA in the third quarter of 2019 was $126.2 million, an increase of 35% compared to the same quarter of 2018. The adoption of IFRS 16 increased Operating EBITDA by $5.9 million, or 6%, compared to the third quarter of 2018.
- Operating netback in the third quarter of 2019 was $29.61/boe, 15% higher than $25.67/boe in the third quarter of 2018 and 19% lower than $36.45/boe in the second quarter of 2019. The adoption of IFRS 16 increased Operating Netback by $0.78/boe, or 3%, compared to third quarter of 2018.
- Capital expenditures during the third quarter of 2019 were $70.8 million compared to $124.0 million in the same prior year quarter.

Shareholder Value Initiatives

- On July 17, 2019, the Company paid a regular dividend that was declared in the second quarter of 2019 in the amount of $15.4 million (C$0.205/share), which included the issuance of 244 Common Shares to shareholders electing to participate in the Company's Dividend Reinvestment Plan ("**DRIP**").
- On August 1, 2019, the Company declared a special dividend of C$0.535/share and a regular dividend of C$0.205/share. The special dividend in the amount of $39.4 million was paid on August 23, 2019, while the regular dividend in the amount of $15.1 million was paid on October 16, 2019. The dividends resulted in the issuance of 2,384 Common Shares to shareholders electing to participate under the DRIP.
- As at October 30, 2019, the Company has paid total dividends of $106.4 million to shareholders during the year, including the issuance of 630,944 Common Shares under the DRIP.
- On November 6, 2019, the Company declared a regular dividend of C$0.205/share, which will be paid on or about January 17, 2020 to shareholders of record at the close of business on January 3, 2020.
- On October 16, 2019, the Company received approval from the Toronto Stock Exchange (the "**TSX**") to purchase up to 6,532,400 Common Shares under a normal course issuer bid (the "**NCIB**") and over a twelve-month period, commencing on October 18, 2019. Under the prior NCIB that expired on July 17, 2019, the Company repurchased for cancellation a total of 2,684,605 Common Shares for $27.7 million.

2. GUIDANCE

The Company has re-affirmed its guidance as updated on August 1, 2019, and results are expected to be towards the favorable end of 2019 guidance ranges for production, operating EBITDA, production costs, and transportation costs. The following table reports the Company's actual results for the nine months period ending September 30, 2019, against guidance.

		2019	
		Guidance (1) (2)	Actual
Average production	(boe/d)	65,000 to 70,000	70,866
Average net production	(boe/d)	60,000 to 65,000	64,764
Production costs	($/boe)	12.00 to 12.50	11.39
Transportation costs	($/boe)	12.50 to 13.50	12.39
Operating EBITDA	($MM)	525 to 575	452
Capital expenditures	($MM)	325 to 375	213

1. The guidance for operating EBITDA and capital expenditures are aggregate ranges for the year.
2. The guidance assumes $65.00/bbl Brent, realized oil price differentials of $3.50/bbl and foreign exchange rate of 3,100 COP to 1 USD.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's producing fields in Colombia and Peru. Refer to the "Further Disclosures" section on page 23 for details of the Company's net production by block.

	Production (in boe/d)				
Producing blocks in Colombia	**Q3 2019**	**Q2 2019**	**Q3 2018**	**YTD 2019**	**YTD 2018**
Heavy oil	33,906	32,462	28,534	32,354	28,566
Light and medium oil	27,514	29,494	29,121	29,783	29,768
Natural gas	2,283	2,454	4,122	2,461	4,498
Total production Colombia	**63,703**	**64,410**	**61,777**	**64,598**	**62,832**
Producing blocks in Peru					
Light and medium oil	6,510	9,975	4,616	6,268	7,900
Total production Peru	**6,510**	**9,975**	**4,616**	**6,268**	**7,900**
Total production	**70,213**	**74,385**	**66,393**	**70,866**	**70,732**

Colombia

Production in Colombia for the three and nine months ended September 30, 2019, increased by 3% to 63,703 boe/d and by 3% to 64,598 boe/d, respectively, compared to the same periods of 2018. Higher production was a result of the growth in the heavy oil unit, mainly in the Quifa and CPE-6 blocks, as a result of development drilling and facilities optimization. This was offset by the managed decline in the light and medium oil and natural gas units, mainly in the Guatiquia block, as the Company awaits permitting and construction of a new drilling pad on the eastern flank of the Coralillo field.

In comparison to the second quarter of 2019, production was 1%, or 707 boe/d, lower during the third quarter of 2019, reflecting the impact of the managed decline from light and medium oil and natural gas blocks (Coralillo field on the Guatiquia light and medium oil block and La Creciente natural gas block).

Peru

Production in Peru for the third quarter of 2019 averaged 6,510 boe/d, an increase of 41%, or 1,894 boe/d, compared with the same quarter of 2018. For the nine months ended September 30, 2019, average production decreased by 21%, to 6,268 boe/d, from 7,900 boe/d in the same period of 2018. Production levels in Peru continue to be unpredictable and primarily correlated with the number of operational days at Block 192, which have fluctuated significantly as force majeure events on the Norperuano pipeline have caused the Company to intermittently shut down production on the block.

In comparison to the second quarter of 2019, production was 3,465 boe/d lower during the third quarter of 2019, reflecting interrupted operations at Block 192 due to a force majeure event on the Norperuano pipeline. As a result of the force majeure events, the service contract relating to Block 192 has been extended and is now expected to expire in March 2020.

Production Reconciled to Sales Volumes

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

					Nine months ended September 30	
		Q3 2019	Q2 2019	Q3 2018	2019	2018
Production	**(boe/d)**	**70,213**	**74,385**	**66,393**	**70,866**	**70,732**
Royalties in-kind Colombia	(boe/d)	(4,936)	(5,712)	(7,208)	(5,152)	(6,647)
Royalties in-kind Peru [(1)]	(boe/d)	(1,006)	(1,559)	(627)	(950)	(1,138)
Net production	**(boe/d)**	**64,271**	**67,114**	**58,558**	**64,764**	**62,947**
Oil inventory (build) draw	(boe/d)	(8,694)	1,369	(805)	(2,156)	(2,164)
Overlift (settlement) positions	(boe/d)	41	(13)	5,383	9	1,936
Sales volumes from E&E assets [(2)]	(boe/d)	(32)	(37)	(898)	(44)	(1,014)
Other inventory movements [(3)]	(boe/d)	(1,208)	(2,328)	(1,167)	(2,444)	(1,229)
Sales volumes	**(boe/d)**	**54,378**	**66,105**	**61,071**	**60,129**	**60,476**
Oil sales volumes	(bbl/d)	52,098	63,794	56,972	57,732	56,001
Natural gas sales volumes	(boe/d)	2,280	2,311	4,099	2,397	4,475
Inventory balance						
Colombia	(bbl)	798,953	454,909	65,497	798,953	65,497
Peru	(bbl)	1,851,080	1,395,343	1,481,916	1,851,080	1,481,916
Inventory ending balance	**(bbl)**	**2,650,033**	**1,850,252**	**1,547,413**	**2,650,033**	**1,547,413**

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" on page 6.
2. Volumes from E&E assets are excluded from total sales volumes, as the related revenue and costs are capitalized under IFRS.
3. Mainly corresponds to operational consumption and quality volumetric compensation.

Oil and gas sales volumes for the three months ended September 30, 2019, were lower than the same period of 2018 and prior quarter of 2019, as the Company continued to experience higher inventory buildup relating to unsold production from Block 192 in Peru due to the Norperuano pipeline force majeure event. In Colombia, higher inventory was due to the timing of cargo shipments. Oil and gas sales volumes for the nine months ended September 30, 2019, were similar to the same period of 2018.

Colombia Royalties - PAP

The Company makes high-price clause participation ("**PAP**") payments to Ecopetrol S.A. and the Agencia Nacional de Hidrocarburos on production at the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo and Arrendajo blocks. The PAP payments are 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 ("**PPI**"). Increases in oil prices can trigger higher PAP obligations, payable both in-kind (reducing the Company's net production) and in cash (increasing royalties).

The Company paid approximately 1.1% (combined cash and in-kind) of its production in the third quarter of 2019 as PAP, which was lower than 5.2% paid in the same quarter of 2018 and lower than 3.1% paid in the previous quarter. The Company paid PAP in-kind volumes averaging 343 bbl/d during the third quarter of 2019, compared with 2,625 bbl/d in the same quarter of 2018, and 1,036 bbl/d in the second quarter of 2019.

During the nine months ended September 30, 2019, the Company paid approximately 2.0% (combined cash and in-kind) of its production as PAP, which was lower than 4.3% paid in the same period of 2018. The Company paid PAP in-kind volumes averaging 489 bbl/d during the nine months ended September 30, 2019, compared with 2,022 bbl/d in the same period of 2018. Lower PAP during all periods was due to lower WTI oil benchmark prices.

Peru Royalties - Block 192 Contract

The Company does not hold a license or working interest on Block 192 in Peru, as it operates the block through a service contract. Under this contract, the volumes produced are owned by Perupetro, Peru's state oil company, and the Company is entitled to in-kind payments on production, which can range from 49% to 84% of production on the block. This percentage is determined by the "R" Factor, related to income and expenses in accordance with the service contract. The Company reports the share of production retained by the government as royalties paid in-kind.

As of September 30, 2019, the Company has received in-kind payments for its services equivalent to 84% of the production from the block, with the balance being retained by Perupetro. Perupetro retained in-kind volumes averaging 1,006 bbl/d and 950 bbl/d, respectively, during the three and nine months ended September 30, 2019, compared with 627 bbl/d and 1,138 bbl/d in the same periods of 2018.

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. There were no instances of overlift or settlement during the quarter.

Realized and Reference Prices

					Nine months ended September 30	
		Q3 2019	**Q2 2019**	**Q3 2018**	**2019**	**2018**
Reference price						
Brent	($/bbl)	62.03	68.47	75.84	65.05	72.75
Average realized prices						
Realized oil price	($/bbl)	59.53	66.45	70.87	62.13	68.62
Realized natural gas price	($/boe)	18.57	19.14	24.71	18.96	23.65
Other revenue (1)	($/boe)	0.09	0.21	0.25	0.15	0.74
Net sales realized price						
Oil and gas sales and other revenue	($/boe)	57.90	65.01	68.02	60.56	66.04
Realized loss on risk management contracts	($/boe)	(0.43)	(0.33)	(10.02)	(0.35)	(10.13)
Royalties	($/boe)	(2.41)	(2.40)	(2.83)	(2.18)	(2.28)
Diluent costs	($/boe)	(1.85)	(2.17)	(1.89)	(1.92)	(1.83)
Net sales realized price	**($/boe)**	**53.21**	**60.11**	**53.28**	**56.11**	**51.80**

1. Includes revenue from infrastructure and other assets, not related to pipeline assets (including Petroelectrica de los Llanos Ltd. ("**PEL**") until its disposal on April 19, 2018).

Average Brent crude oil benchmark prices during the three and nine months ended September 30, 2019, were lower by 18% and 11%, respectively, compared with the same periods of 2018. The reduction in global crude oil prices was mostly attributable to a weaker global economic outlook, lower manufacturing and industrial output, as well as the lingering trade war between the U.S. and China that has dampened market and demand sentiment. This was partially offset by the realization of narrower price differentials for the Company's blend as the regional market remains short on heavy grade crude oil following U.S. sanctions on Venezuela, and the 5% tariff imposed by China on oil imports coming from the U.S. In comparison to the second quarter of 2019, crude oil prices weakened with the Brent benchmark price decreasing by an average of 9.4%, or $6.44/bbl, during the third quarter of 2019, as OPEC´s production cuts could not offset the weak macroeconomic factors.

For the three and nine months ended September 30, 2019, the Company's net sales realized price was $53.21/boe and $56.11/boe, respectively, which is stable in comparison with the third quarter of 2018, and 8% higher compared to the nine months ended September 30, 2018, mainly due to significantly lower realized losses from risk management contracts in 2019. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 11. In comparison to the second quarter of 2019, the net sales realized price decreased by 11%, or $6.90/boe, primarily driven by a decrease in the benchmark oil price.

Operating Netback

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

	Q3 2019		Q2 2019		Q3 2018	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	266,217	53.21	361,596	60.11	299,343	53.28
Production costs (2)	(74,939)	(11.60)	(75,598)	(11.17)	(84,560)	(13.84)
Transportation costs (3)	(70,960)	(12.00)	(76,260)	(12.49)	(74,210)	(13.77)
Operating Netback (4)	**120,318**	**29.61**	**209,738**	**36.45**	**140,573**	**25.67**
		(boe/d)		(boe/d)		(boe/d)
Sales volumes (D&P) (5)		54,378		66,105		61,071
Production (6)		70,213		74,385		66,393
Net production (6)		64,271		67,114		58,558

1. Per boe is calculated using sales volumes from D&P assets. Refer to the "Realized and Reference Prices" section on page 6.
2. Per boe is calculated using production.
3. Per boe is calculated using net production after royalties. Refer to the "Other Selected Operating Costs" section on page 9 for fees that are not included in table.
4. Refer to the "Non-IFRS Measures" section on page 16 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 4 and 5.

Operating netback for the third quarter of 2019 was $29.61/boe compared to $25.67/boe in the same quarter of 2018. The increase was primarily due to lower production and transportation costs per boe in the current quarter. Production costs per boe decreased due to higher total production in the current quarter and lower hired services, well services, maintenance activities and personnel-related costs. Transportation costs per boe decreased mainly due to lower sales volumes transported from Block 192 in Peru and lower costs from the acquisition of transportation capacity rights on the Oleoducto Central S.A. ("**Ocensa**") pipeline.

In comparison to the second quarter of 2019, operating netback decreased from $36.45/boe to $29.61/boe, primarily as a result of lower benchmark oil prices.

The following table provides a summary of the Company's year-to-date netbacks:

	Nine months ended September 30			
	2019		2018	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	921,086	56.11	855,103	51.80
Production costs (2)	(220,295)	(11.39)	(239,959)	(12.43)
Transportation costs (3)	(219,126)	(12.39)	(218,723)	(12.73)
Operating Netback (4)	**481,665**	**32.33**	**396,421**	**26.64**
		(boe/d)		(boe/d)
Sales volumes (D&P) (5)		60,129		60,476
Production (6)		70,866		70,732
Net production (6)		64,764		62,947

References 1 through 6 are consistent with those included in the quarterly Operating Netback table above.

Operating netback for the nine months ended September 30, 2019, increased by 21% to $32.33/boe from $26.64/boe in the same period of 2018. The increase was primarily due to higher net sales realized price from lower realized losses on risk management contracts, as well as lower production and transportation costs per boe during the period. On a per boe basis, the decrease in production and transportation costs are similar to the reasons described in the quarterly netback analysis above.

Sales

($M)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Oil and gas sales and other revenue [(1)]	289,641	382,189	994,149	1,090,283
Realized loss on risk management contracts	(2,135)	(56,297)	(5,714)	(167,303)
Royalties	(12,051)	(15,902)	(35,866)	(37,624)
Diluent costs	(9,238)	(10,647)	(31,483)	(30,253)
Net sales	**266,217**	**299,343**	**921,086**	**855,103**
$/boe using sales volumes from D&P assets	53.21	53.28	56.11	51.80

1. In Colombia, for the three and nine months ended September 30, 2019, oil and gas sales and other revenue were $286.4 million and $934.0 million compared with $361.4 million and $1,011.6 million, respectively, in the same periods of 2018. In Peru, for the three and nine months ended September 30, 2019, oil and gas sales and other revenue were $3.3 million and $60.2 million, compared with $20.8 million and $78.7 million, respectively, in the same periods of 2018.

Oil and gas sales and other revenue for the three months ended September 30, 2019, decreased by $92.5 million compared to the same period in 2018, mainly due to lower oil and gas prices and volumes sold. Oil and gas and other revenue for the nine months ended September 30, 2019, decreased by $96.1 million compared to the same period in 2018, mainly due to lower oil and gas prices.

Net sales for the three and nine months ended September 30, 2019, decreased by $33.1 million and increased by $66.0 million, respectively, compared with the same periods in 2018. The following table describes the various factors that impacted net sales:

($M)	Three months ended September 30	Nine months ended September 30
Net sales for the period ended September 30, 2018	299,343	855,103
Decrease due to 15% lower oil and gas price (YTD 8% lower)	(50,664)	(89,884)
Lower realized loss on risk management contracts	54,162	161,589
Decrease in royalties	3,851	1,758
Decrease due to lower volumes sold of 6,693 boe/d or 11% (YTD 347 boe/d or 1% lower)	(41,884)	(6,250)
Decrease (increase) in diluent costs	1,409	(1,230)
Net sales for the period ended September 30, 2019	**266,217**	**921,086**

Royalties

($M)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Royalties Colombia	11,889	15,612	35,302	36,926
Royalties Peru	162	290	564	698
Royalties	**12,051**	**15,902**	**35,866**	**37,624**
$/boe using sales volumes from D&P assets	2.41	2.83	2.18	2.28

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three and nine months ended September 30, 2019, royalties decreased by $3.9 million and $1.8 million, respectively, compared to the same periods in 2018, primarily due to the impact from lower WTI oil benchmark prices. The Company's royalty burden is directly correlated with changes in WTI oil benchmark prices due to the price sensitivity of PAP in Colombia. Refer to the "Production" section on page 4 for further details of royalties paid in-cash and in-kind.

Oil and Gas Operating Costs

($M)	Three months ended September 30 2019	2018	Nine months ended September 30 2019	2018
Production costs	74,939	84,560	220,295	239,959
Transportation costs	70,960	74,210	219,126	218,723
Diluent costs	9,238	10,647	31,483	30,253
Overlift	164	37,212	159	42,732
Inventory valuation	(24,526)	(13,038)	(20,946)	(20,999)
Total oil and gas operating costs	**130,775**	**193,591**	**450,117**	**510,668**

Total oil and gas operating costs for the three and nine months ended September 30, 2019, decreased by 32% and 12%, respectively, compared to the same periods in 2018. Total oil and gas operating costs changed mainly due to the following:

- Production costs decreased by 11% and 8% in the three and nine months ended September 30, 2019, respectively, compared with the same periods of 2018, mainly as a result of lower production costs in Peru primarily due to higher maintenance activities in Block 192 during the third quarter of 2018, and lower hired services, well services, maintenance activities and personnel-related expenses from cost savings and operational efficiency initiatives.

- Transportation costs decreased by 4% in the three months ended September 30, 2019, compared to the same quarter of 2018, primarily due to lower sales volumes transported from Block 192 in Peru and the acquisition of transportation capacity rights related to the Ocensa pipeline in Colombia, which eliminated the monthly cost of $1.5 million. Additionally, transportation costs were lower by $2.4 million as certain storage facilities are now capitalized due to the adoption of IFRS 16. Transportation costs for the nine months ended September 30, 2019, were comparable with the same period of 2018.

- Diluent costs decreased by 13% for the three months ended September 30, 2019, compared to the same quarter of 2018, mainly due to lower diluent costs from favorable natural gasoline market conditions. Diluent costs for the nine months ended September 30, 2019, were comparable with the same period of 2018.

- Overlift decreased during the three and nine months ended September 30, 2019, as the Company did not have overlift positions compared to the same prior year periods of 2018.

- Inventory valuation for the three months ended September 30, 2019, increased by $11.5 million due to higher inventory in Peru as a result of the force majeure event on the Norperuano pipeline and Colombia due to the timing of cargo shipments. For the nine months ended September 30, 2019, inventory valuation remained relatively constant.

Other Selected Operating Costs

($M)	Three months ended September 30 2019	2018	Nine months ended September 30 2019	2018
Fees paid on suspended pipeline capacity	—	5,633	—	82,372
Payments under terminated pipeline contracts	—	15,578	—	15,578
Reversal of provision related to PAP	—	(21,832)	—	(21,832)

Fees paid on suspended pipeline capacity and payments under terminated pipeline capacity were $Nil for the three and nine months ended September 30, 2019, due to the termination of the transportation contracts with Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") and Cenit Transporte y Logistica de Hidrocarburos S.A.S. in July 2018.

Additionally, during the third quarter 2018, the Company recognized the reversal of a provision related to the PAP. The provision was reversed as an external legal opinion supported the Company's technical interpretation that the clause would not apply to a certain designated exploitation area within one of its blocks.

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($M)	**2019**	**2018**	**2019**	**2018**
General and administrative	18,476	22,962	53,175	71,183

General and administrative expenses for the three and nine months ended September 30, 2019, decreased by 20% and 25%, respectively, compared to the same periods in 2018, primarily due to a reduction in employee-related expenses from the Company's organizational restructuring in 2018 and lower office lease costs for the three and nine months ended September 30, 2019, of $1.5 million and $4.5 million, respectively, due to the adoption of IFRS 16.

Depletion, Depreciation and Amortization

	Three months ended September 30		Nine months ended September 30	
($M)	**2019**	**2018**	**2019**	**2018**
Depletion, depreciation and amortization	94,019	78,041	286,257	236,290

Depletion, depreciation and amortization expense ("**DD&A**") increased by 20% and 21% for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. The increase was primarily due to higher oil production in Colombia, amortization of the Ocensa rights acquired, and a higher depreciable base resulting from the recognition of $64.1 million in right-of-use ("**ROU**") assets on the adoption of IFRS 16. For the three and nine months ended September 30, 2019, the depreciation relating to the ROU assets resulted in increases of $6.3 million and $18.3 million, respectively, and from Ocensa rights $3.2 million and $6.9 million, respectively.

Impairment, Exploration Expense and Other

	Three months ended September 30		Nine months ended September 30	
($M)	**2019**	**2018**	**2019**	**2018**
Impairment of other assets	36,628	—	36,628	—
Impairment of exploration and evaluation assets	8,024	24,735	17,688	26,742
Other impairment	587	5,475	4,745	5,744
Impairment of investment in associates	—	23,296	—	142,172
Impairment of properties plant and equipment	—	4,786	—	4,786
Impairment of assets held for sale - transmission line assets	—	—	—	9,125
Total impairment	**45,239**	**58,292**	**59,061**	**188,569**
Exploration - pre-licence costs	1,569	779	3,063	779
Change in asset retirement obligation	(417)	—	1,130	—
Exploration expense and other	**1,152**	**779**	**4,193**	**779**
Total impairment, exploration expense and other	**46,391**	**59,071**	**63,254**	**189,348**

For the three and nine months ended September 30, 2019, the Company recognized an impairment charge of $36.6 million related to a long-term receivable from Infrastructure Ventures Inc. ("**IVI**"), as a result of impairment indicators related to uncertainties with respect to the recoverability of future project opportunities at the port subsidiary of IVI, Sociedad Portuaria Puerto Bahía S.A. ("**Puerto Bahia**"), which would impact the cash generation of Puerto Bahia. Additionally, for the three and nine months ended September 30, 2019, the Company recognized an impairment charge of $8.0 million and $17.7 million, respectively, of E&E assets mainly due to technical results and changes in development plans for certain exploration projects from Colombia (2018: $24.7 million and $26.7 million).

The Company recognized an impairment charge of $23.3 million and $131.0 million for the three and nine months ended September 30, 2018, respectively, for associate investee Bicentenario, where the recoverable amount of the investment was calculated based on its value-in-use ("**VIU**") using a discounted dividends cash flow model. In addition, for the nine months ended September 30, 2019, the Company recognized an impairment charge of $11.2 million on the investment in Interamerican Energy Corp. ("**Interamerican**") resulting from the acceptance of a bid offer received that was lower than carrying value.

Non-Operating Costs

($M)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Finance income	5,580	7,567	17,082	18,251
Finance expenses	(19,732)	(13,626)	(48,054)	(38,056)
Foreign exchange (loss) gain	(3,735)	(1,094)	(1,452)	9,712
Other (loss) income, net	(1,359)	(2,606)	9,438	(3,909)

Finance Income and Expenses

Finance expenses includes interest on the Company's long-term debt, leases liabilities and fees on letters of credit. Finance income of $5.6 million and $7.6 million for the three and nine months ended September 30, 2019, respectively, were 26% and 6% lower than the same periods of 2018, primarily due to lower interest income as a result of lower average cash balances. For the three and nine months ended September 30, 2019, finance expenses increased to $19.7 million and $48.1 million, from $13.6 million and $38.1 million in the same periods of 2018, primarily due to interest on lease liabilities recognized on the adoption of IFRS 16.

Foreign Exchange (Loss) Gain

For the three and nine months ended September 30, 2019, foreign exchange loss was $3.7 million and $1.5 million, respectively, compared with a loss of $1.1 million and a gain of $9.7 million in the same periods of 2018, primarily due to the impact of the COP's depreciation against the USD on the translation of the Company's net working capital balances in COP.

Other Loss, net

For the three months ended September 30, 2019, other loss was $1.4 million compared with a loss of $2.6 million in the same quarter of 2018, mainly due to environmental contingencies recognized in the prior year. For the nine months ended September 30, 2019, other income was $9.4 million compared with a loss of $3.9 million in the same prior year period, primarily due to a gain of $10.9 million resulting from the fair value equity adjustment on acquisition of CGX Energy Inc. ("**CGX**").

Gain (Loss) on Risk Management Contracts

($M)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Realized loss on risk management contracts (1)	(2,135)	(56,297)	(5,714)	(167,303)
Unrealized gain on risk management contracts (2)	4,338	61,830	4,611	75,945
Total gain (loss) on risk management contracts	**2,203**	**5,533**	**(1,103)**	**(91,358)**

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

For the three and nine months ended September 30, 2019, realized loss on risk management contracts was $2.1 million and $5.7 million, respectively. This was significantly lower than the same prior year periods of 2018, primarily as a result of differences in the underlying hedging instruments that expired or settled during each period. During the first nine months of 2019, Brent oil put options have expired (which limited the loss to the premiums paid) compared to the same period of 2018 when zero cost collars were settled at oil prices that were significantly higher than average ceiling contract prices. Refer further to the risk management strategy described in the section "Risk Management Contracts - Brent Crude Oil" below.

For the three and nine months ended September 30, 2019, the Company recognized an unrealized gain on risk management contracts of $4.3 million and $4.6 million, respectively, due to the decrease in the crude oil benchmark forward prices over the contract periods. This is compared to an unrealized gain of $61.8 million and $75.9 million, respectively, in the same prior year periods, primarily related to the reversal of prior unrealized amounts as zero cost collars settled during the period.

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. Consistent with the Company's risk management goals and priorities, the hedging strategy is designed to protect the Company's capital program, debt service requirements and potential future dividends. In 2019, the Company executed a risk management strategy using a layered approach primarily with put options to protect against downward price movements while retaining the opportunity to realize the upside from rising prices, in contrast to 2018 when the Company only used zero cost collars. For 2020, the Company has added to its hedging program using a mix of derivatives instruments including put options, zero cost collars, three-way collar and put spreads.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads $**	**Assets**	**Liabilities**
Put options	October 2019 to March 2020	Brent	2,124,000	59.05	6,860	—
Zero cost collars	October 2019 to March 2020	Brent	1,880,000	57.82 / 75.50	5,994	—
Three-way collar	April 2020 to June 2020	Brent	960,000	45 / 55 /74.68	2,324	—
Put spread	January 2020 to June 2020	Brent	1,170,000	47/57	4,102	—
Total as at September 30, 2019					19,280	—

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. The Company monitors its exposure to such foreign currency risks. As at September 30, 2019, the Company has entered into foreign currency derivatives contracts from October 2019 to June 2020, for $209.5 million (zero cost collars) to reduce its foreign currency exposure associated with operating expenses incurred in COP.

					Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume USD $M**	**Avg. Put / Call; Par forward COP**	**Assets**	**Liabilities**
Zero cost collars	October 2019 to June 2020	COP / USD	$ 209,500	3,156 / 3,556	—	3,231
Total as at September 30, 2019					**—**	**3,231**

Income Tax Expense

	Three months ended September 30		Nine months ended September 30	
($M)	**2019**	**2018**	**2019**	**2018**
Current income tax expense	(28,744)	(8,787)	(37,671)	(24,570)
Deferred income tax (expense) recovery	(1,155)	28,604	142,858	21,916
Total income tax (expense) recovery	**(29,899)**	**19,817**	**105,187**	**(2,654)**

The current income tax expense for the third quarter of 2019 was $28.7 million, compared to $8.8 million in the same quarter of 2018. This increase was primarily due to a charge of $25.4 million relating to changes in old tax assessments in Colombia. The deferred income tax expense for the third quarter of 2019 was $1.2 million related to the utilization of the deferred tax asset in Colombia, compared to a recovery of $28.6 million in the same period of 2018, primarily as a result of the recognition of a deferred tax asset in Colombia. The usage of the deferred tax asset in the third quarter of 2019 was lower than expected due to the buildup of inventory and timing of cargo shipments in Colombia.

The current income tax expense for the nine months ended September 30, 2019, was $37.7 million, compared to $24.6 million in the same period in 2018, primarily due to the charge of $25.4 million in the quarter as described above. The deferred income tax recovery for the nine months ended September 30, 2019, was $142.9 million compared to a recovery of $21.9 million in the same period of 2018 from the recognition of higher deferred tax assets in Colombia during 2019.

For more information, refer to Note 8 of the Interim Financial Statements.

Net (Loss) Income

($M)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Net (loss) income attributable to equity holders of the Company	(49,117)	45,105	224,879	(142,452)
Per share – basic	(0.50)	0.45	2.29	(1.42)
Per share – diluted	(0.50)	0.45	2.26	(1.42)

For the three months ended September 30, 2019, the Company reported a net loss of $49.1 million driven by higher income tax expense and impairment charges relating to Puerto Bahia and certain E&E assets. This compares to a net income of $45.1 million in the third quarter of 2018, which included gains relating to the recognition of a deferred income tax asset and the reversal of a PAP provision. For the nine months ended September 30, 2019, the Company reported a net income of $224.9 million compared to a net loss of $142.5 million in the same period of 2018 as a result of lower impairment charges of $125.1 million, higher deferred income tax recovery of $120.9 million, no fees paid on suspended pipeline capacity and payments under terminated pipeline capacity totalling $98.0 million.

Capital Expenditures

($M)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Maintenance and development drilling	44,491	65,744	145,191	148,877
Exploration activities [(1)]	18,249	31,716	42,429	84,212
Facilities and infrastructure	7,416	26,528	23,305	50,040
Other	605	41	2,542	6,554
Total capital expenditures	**70,761**	**124,029**	**213,467**	**289,683**

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

Capital expenditures of $70.8 million and $213.5 million for the three and nine months ended September 30, 2019 were lower by 43% and 26%, respectively, compared to the same prior year periods primarily due to higher spending in 2018 on production facilities (such as the water handling expansion in Quifa) and higher cost exploration wells. During the third quarter of 2019, the company drilled a total of 30 development wells and one exploration well compared to 38 development wells and one exploration well in the third quarter of 2018. During the nine months ended September 30, 2019, a total of 98 development wells and six exploration wells were drilled, compared to 98 development wells and five exploration wells drilled in the same period of 2018. The Company continued investing in exploration and development drilling with six rigs in operation during the third quarter of 2019, including four in the Quifa heavy oil block and two in the light oil-focused blocks (Guatiquia and Cubiro blocks).

Selected Quarterly Information

		2019			2018				2017
		Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Operational and financial results									
Oil production	(bbl/d)	67,930	71,931	65,323	68,661	62,271	67,522	68,983	64,559
Natural gas production	(boe/d)	2,283	2,454	2,651	3,263	4,122	4,504	4,875	5,315
Production	(boe/d)	70,213	74,385	67,974	71,924	66,393	72,026	73,858	69,874
Oil and gas natural gas sales volumes	(boe/d)	54,378	66,105	59,968	50,298	61,071	67,822	52,440	65,481
Brent price	($/bbl)	62.03	68.47	63.83	68.60	75.84	74.97	67.23	61.46
Oil and gas sales and other revenue	($/boe)	57.90	65.01	58.08	60.06	68.02	67.82	61.34	56.19
Realized loss on risk management contracts	($/boe)	(0.43)	(0.33)	(0.30)	(5.55)	(10.02)	(11.12)	(8.98)	(2.93)
Royalties	($/boe)	(2.41)	(2.40)	(1.74)	(2.94)	(2.83)	(2.19)	(1.74)	(1.35)
Diluent costs	($/boe)	(1.85)	(2.17)	(1.71)	(2.22)	(1.89)	(1.74)	(1.88)	(1.00)
Net sales realized price	($/boe)	53.21	60.11	54.33	49.35	53.28	52.77	48.74	50.91
Production costs (1)	($/boe)	(11.60)	(11.17)	(11.40)	(12.76)	(13.84)	(12.44)	(11.11)	(11.98)
Transportation costs (1)	($/boe)	(12.00)	(12.49)	(12.70)	(12.89)	(13.77)	(11.81)	(12.68)	(14.28)
Operating netback (1)	($/boe)	29.61	36.45	30.23	23.70	25.67	28.52	24.95	24.65
Revenue (2)	($M)	277,676	377,347	377,527	265,109	366,511	405,198	283,667	344,862
Net (loss) income	($M)	(49,117)	227,809	46,187	(116,631)	45,105	(184,436)	(3,121)	(32,544)
Per share – basic	($)	(0.50)	2.32	0.47	(1.17)	0.45	(1.84)	(0.03)	(0.33)
Per share – diluted	($)	(0.50)	2.29	0.47	(1.17)	0.45	(1.84)	(0.03)	(0.33)
General and administrative (1)	($M)	18,476	18,207	16,492	21,839	22,962	26,168	22,053	24,450
Operating EBITDA (1)	($M)	126,155	181,159	144,855	118,398	93,455	124,667	85,988	104,316
Capital expenditures	($M)	70,761	73,487	69,219	156,400	124,029	86,813	78,841	111,213

1. Effective January 1, 2019, the Company adopted IFRS 16 on a modified retrospective basis and therefore amounts reported for period to 2019 have not been restated and may not be comparable. Refer to Note 2 of the Interim Financial Statements.
2. Revenue for periods prior to 2018 are different from those previously reported as a result of the adoption of IFRS 15, effective January 1, 2018. On adoption of the new standard, realized gains and losses on risk management contracts are no longer included in revenue.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, changes in inventory balances, timing of cargo shipments, movements in the Brent benchmark oil price and fluctuations in realized oil price differentials. The Company's production levels in Colombia have been stable with increases in heavy oil blocks partially offset by natural declines on mature blocks. The Company has had fluctuating production in Peru since operations at Block 192 have experienced periods of suspension under force majeure due to issues on the Norperuano pipeline. Trends in the Company's net income and loss are also impacted most significantly by deferred income tax, DD&A and net impairment charges of oil, gas and other assets, gains and losses from risk management activities that fluctuate with changes in hedging strategies and forward market prices.

Please refer to the Company's previously issued annual and interim MD&As for further information regarding changes in prior quarters.

Midstream Activities

The Company has investments in certain infrastructure and midstream assets. These assets include the Company's investments in pipelines, storage and other facilities relating to the distribution and exportation of crude oil products in Colombia. The Company's significant midstream assets are accounted for using the equity method of accounting, which 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. The following section provides a summary and update of these investments.

Pacific Midstream Limited ("PML")

The Company holds a 59.9% interest in PML, which has a 35% equity investment in Oleoducto de los Llanos Orientales S.A. ("**ODL**"). ODL owns the ODL pipeline, which runs from the Rubiales and Quifa fields to the Monterrey Station or Cusiana Station in Casanare Department.

For the nine months ended September 30, 2019, the Company's share of income from ODL increased by $6.1 million compared to the same period of 2018, primarily due to higher volumes transported in the Llanos region and the impact of foreign exchange fluctuations. During the nine months ended September 30, 2019, the Company recognized gross dividends of $26.9 million, which were declared and paid by ODL.

Bicentenario

The Company holds a 43.0% interest in Bicentenario, which owns the Bicentenario pipeline ("**BIC pipeline**") that runs from 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, which runs to the Coveñas terminal on Colombia's Caribbean coastline in the Sucre Department.

On March 22, 2019, the Company increased its net ownership interest in Bicentenario from 26.4% to 43.0% through the acquisition of PML's ownership interest in Bicentenario for approximately $84.8 million. The International Financial Corporation and related funds exercised their right requiring the Company to purchase PML's interest in Bicentenario as a result of the termination of the Company's take or pay contracts with Bicentenario because the BIC pipeline was non-operational for six consecutive months. The net cost of the acquisition to the Company was approximately $34.0 million after the proceeds of the transaction were distributed by PML to its shareholders, including the Company.

For the nine months ended September 30, 2019, the Company's share of income from Bicentenario decreased by $10.6 million compared to the same period of 2018 due to lower pipeline revenue after the termination of the Company's transportation contracts with Bicentenario in July 2018. For the nine months ended September 30, 2019, the Company recognized gross dividends of $34.4 million, which were declared but not paid by Bicentenario. As at September 30, 2019, the discounted carrying value of dividends receivable from Bicentenario is $36.9 million ($42.7 million undiscounted).

Infrastructure Ventures Inc. ("IVI") (Formerly Pacific Infrastructure Ventures Inc.)

The Company holds a 39.2% interest in Puerto Bahia through its interest in IVI. Puerto Bahia operates a multipurpose port facility in the Bay of Cartagena. The port, which consists of a hydrocarbon terminal and a dry cargo terminal, is adjacent to the Bocachica access channel of the Cartagena Bay, and is strategically located near the Cartagena Refinery and the Panama Canal.

On April 30, 2019, IVI received a request to fund $10.9 million to Puerto Bahia as required under the Equity Contribution Agreement ("**ECA**") signed on October 4, 2013. Under the ECA, the Company and IVI agreed to jointly and severally cause equity contributions (via debt or equity) to Puerto Bahia up to the aggregate amount of $130.0 million. Amounts advanced under the ECA are designated to the repayment of principal and interest from debt obligations of Puerto Bahia. On June 14, 2019, the Company disbursed $10.9 million to Puerto Bahia bearing interest of 14%, and a default interest rate of 16% in the event of non-payment upon maturity in one year. To date, the Company has advanced a total of $52.1 million under the ECA (of which $30.4 million is currently in default).

For the nine months ended September 30, 2019, the Company's share of loss from IVI increased by $11.2 million compared to the same period of 2018, mainly due to a higher unrealized loss on the revaluation of USD denominated debt. As the carrying amount of the equity investment in IVI was reduced to $Nil at December 31, 2018, the Company has recorded its share of losses during 2019 as a reduction to other receivables with IVI. As of September 30, 2019, the carrying value of the Company's net investment (which includes loans and long term receivables) in IVI has decreased to $78.4 million compared to $110.8 million as at December 31, 2018, due to the recognition of the equity method losses and an impairment charge of $36.6 million from uncertainties in future cash flows.

The Company's consolidated statements of cash flows and financial position includes the following amounts relating to midstream activities:

	Nine months ended September 30,							
Statements of Cash Flows	**2019**				**2018**			
($M)	**ODL**	**Bicentenario (1)**	**IVI**	**Total**	**ODL**	**Bicentenario**	**IVI**	**Total**
Dividends received from associates	32,704	—	—	32,704	20,931	27,966	—	48,897
Dividends paid to NCI	(12,515)	—	—	(12,515)	(7,628)	(10,190)	—	(17,818)
Cash flow from midstream dividends	**20,189**	**—**	**—**	**20,189**	**13,303**	**17,776**	**—**	**31,079**
Puerto Bahia ECA (2)	—	—	(10,900)	(10,900)	—	—	(30,461)	(30,461)
Net cash flow from midstream investments	**20,189**	**—**	**(10,900)**	**9,289**	**13,303**	**17,776**	**(30,461)**	**618**

1. Excludes dividends paid to non-controlling interest related to the acquisition of PML's ownership interest in Bicentenario.
2. Included as additions to Other Assets.

Statements of Financial Position	**As at September 30, 2019**				**As at December 31, 2018**			
($M)	**ODL**	**Bicentenario**	**IVI**	**Total**	**ODL**	**Bicentenario**	**IVI**	**Total**
Dividends receivable	—	36,878	—	36,878	9,047	14,447	—	23,494
Puerto Bahia ECA	—	—	59,756	59,756	—	—	43,947	43,947
Puerto Bahia other loan and receivables	—	—	18,666	18,666	—	—	66,825	66,825
Long-term receivable (1)	**—**	**36,878**	**78,422**	**115,300**	**9,047**	**14,447**	**110,772**	**134,266**
Investment in associates (equity)	124,873	63,229	—	188,102	117,368	73,743	—	191,111
Net book value of midstream investments	**124,873**	**100,107**	**78,422**	**303,402**	**126,415**	**88,190**	**110,772**	**325,377**

1. Included as Other Assets

Non-IFRS Measures

This MD&A contains the following terms that do not have standardized definitions in IFRS: "operating EBITDA", "operating netback" and "net sales". 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'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 tax expense, net finance costs and DD&A.

Operating EBITDA represents the operating results of the Company's primary business, excluding the items noted above, including fees paid on suspended pipeline capacity, other investments (such as infrastructure assets), certain non-cash items (such as impairments, foreign exchange and unrealized risk management contracts, and share-based compensation) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA, as they are not indicative of the underlying core operating performance of the Company.

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

	Three months ended September 30		Nine months ended September 30	
($M)	**2019**	**2018**	**2019**	**2018**
Net (loss) income	(49,117)	45,105	224,879	(142,452)
Fees paid on suspended pipeline capacity	—	5,633	—	82,372
Payments under terminated pipeline contracts	—	15,578	—	15,578
Share-based compensation	1,314	1,042	3,031	3,876
Depletion, depreciation and amortization	94,019	78,041	286,257	236,290
Impairment and exploration expenses	46,391	59,071	63,254	189,348
Reversal of provision related to high-price clause	—	(21,832)	—	(21,832)
Restructuring, severance and other costs	5,463	2,108	8,951	6,500
Share of income from associates	(17,183)	(19,239)	(60,434)	(74,649)
Foreign exchange loss (gain)	3,735	1,094	1,452	(9,712)
Finance income	(5,580)	(7,567)	(17,082)	(18,251)
Finance expenses	19,732	13,626	48,054	38,056
Unrealized gain on risk management contracts	(4,338)	(61,830)	(4,611)	(75,945)
Other loss (income), net	1,359	2,606	(9,438)	3,909
Loss on extinguishment of debt	—	—	—	25,628
Income tax expense (recovery)	29,899	(19,817)	(105,187)	2,654
Non-controlling interests	461	(164)	13,043	(8,107)
Reclassification of currency translation adjustments	—	—	—	50,847
Operating EBITDA	**126,155**	**93,455**	**452,169**	**304,110**

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 exclusion of diluent cost 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 do not include the 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 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 and other revenue, realized gains and losses from risk management contracts less royalties and diluent cost) divided by the total sales volumes from D&P assets. A reconciliation of this calculation is provided below:

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Net sales ($M)	266,217	299,343	921,086	855,103
Denominator				
Sales volumes (D&P) - (boe)	5,002,776	5,618,537	16,415,217	16,509,850
Net sales realized price ($/boe)	53.21	53.28	56.11	51.80

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

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Production costs ($M)	74,939	84,560	220,295	239,959
Denominator				
Production (boe)	6,459,596	6,108,156	19,346,323	19,309,836
Production costs ($/boe)	11.60	13.84	11.39	12.43

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

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Transportation costs ($M)	70,960	74,210	219,126	218,723
Denominator				
Net production (boe)	5,912,932	5,387,305	17,680,692	17,184,464
Transportation costs ($/boe)	12.00	13.77	12.39	12.73

4. LIQUIDITY AND CAPITAL RESOURCES

The Company's principal liquidity and capital resource requirements consist of the following:

- Capital expenditures for exploration, production and development, including growth plans;
- Costs and expenses relating to operations, commitments and existing contingencies;
- Debt service requirements relating to existing and future debt; and
- Enhancing shareholder returns through dividends and share repurchases.

The Company expects to fund 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.

As at September 30, 2019, the Company had total cash balances of $442.3 million (including restricted cash of $128.3 million), which is a decrease of $146.1 million as compared to the prior year-end, primarily due to $85.6 million of dividends paid to equity holders of the Company, $9.9 million related to share repurchases from equity holders, $18.3 million of lease payments and $48.5 million related to the acquisition of Transporte Incorporado's transportation capacity rights related to the Ocensa pipeline.

As at September 30, 2019, total cash balances include short and long-term restricted cash of $128.3 million, a decrease of $14.0 million as compared to the prior year-end, primarily due to a new credit line of $11.4 million that allowed the Company to issue a standby letter of credit ("**SBLCs**"), releasing the restricted cash that was a guarantee for abandonment obligations.

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. The main components of restricted cash are long-term abandonment funds and cash collateral required in certain legal processes. Abandonment funds are expected to be released in the long-term as assets are required to be abandoned. Cash collateral for legal processes are expected to be released as the processes are closed.

As at September 30, 2019, the Company had a working capital surplus of $125.0 million, a decrease of $90.7 million as compared to $215.7 million at the prior year-end, primarily due to the increase of current lease liabilities resulting from the adoption IFRS 16 and dividends paid to equity holders. The Company believes that working capital balances in conjunction with future cash flows from operations and available credit facilities are sufficient to support the Company's normal operating requirements, capital expenditures and financial commitments on an ongoing basis.

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.

Letter of Credit Facility

On May 17, 2018, the Company entered into a $100.0 million unsecured letter of credit facility (the "**Unsecured LC Facility**") with a maturity date of May 17, 2020. In November 2018, the Unsecured LC facility was reduced to $60.0 million. As of September 30, 2019, the outstanding letters of credit issued and maintained under the Unsecured LC Facility for exploration and operational commitments totaled $37.1 million. The lenders receive an amount equal to 3.0% per annum on any undrawn issued and outstanding amounts of the letters of credit, due and payable in arrears on the last business day of each calendar month. If any amounts are drawn under the Unsecured LC Facility, interest accrues at 6% per annum.

Guarantees

The Company has various guarantees in place in the normal course of business. As at September 30, 2019, in addition to letters of credit issued from the Unsecured LC Facility, the Company has $23.1 million of outstanding letters of credit to guarantee exploration and abandonment commitments. The lenders under these credit lines receive a fee equal to 3.0% per annum.

Covenants

The Unsecured Notes are senior, unsecured and rank equal in right of payment with all of the existing and future senior unsecured debt and are guaranteed by the Company's principal subsidiaries. Under the terms of both the Unsecured Notes and the Unsecured LC Facility, the Company may (excluding its unrestricted subsidiaries), 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 the said 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. The Company is also permitted to make certain restricted payments, including dividends and share buybacks, in an amount up to $100 million per year starting in 2018, plus accumulated net income starting in 2019. The unused basket for such payments accumulates in subsequent years. To make any restricted payment, the Company must comply with a consolidated debt to consolidated adjusted EBITDA ratio of less than or equal to 2.5:1.0, and ensure a cash balance of at least $200 million as of the last day of the most recent fiscal quarter. As at September 30, 2019, the Company is in compliance with such covenants.

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. 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.
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.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at September 30, 2019, undiscounted and by calendar year, are presented below:

As at September 30, 2019 ($M)	2019	2020	2021	2022	2023	2024 and Beyond	Total
Financial obligations							
Long-term debt, including interest payments	16,975	33,950	33,950	33,950	366,975	—	485,800
Lease liabilities	33,122	32,222	12,177	7,990	1,104	—	86,615
Total financial obligations	**50,097**	**66,172**	**46,127**	**41,940**	**368,079**	**—**	**572,415**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	19,055	64,481	66,141	67,842	69,588	107,687	394,794
Puerto Bahia take-or-pay agreement (1)	6,339	25,860	26,432	—	—	—	58,631
ODL ship-or-pay agreement	11,804	29,075	1,150	—	—	—	42,029
Bicentenario take-or-pay storage agreements	1,813	7,254	7,254	7,254	7,254	5,587	36,416
Other transportation agreements	9,227	30,906	30,357	30,285	29,444	133,491	263,710
Exploration commitments							
Minimum work commitments	20,658	101,202	125,175	48,035	12,950	—	308,020
Other commitments							
Operating purchases and leases (2)	18,984	8,388	7,032	7,005	6,632	11,014	59,055
Community obligations	5,255	70	—	—	—	—	5,325
Total commitments	**93,135**	**267,236**	**263,541**	**160,421**	**125,868**	**257,779**	**1,167,980**

1. Excludes the lease component for ROU assets, which were recognized as lease liabilities upon the adoption of IFRS 16.
2. Excludes lease liabilities recognized on the Consolidated Statements of Financial Position upon the adoption of IFRS 16. Operating purchases and leases represent contractual commitment for service contracts and other short-term and low-value leases.

Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company's financial position, results of operations or cash flows. Other than changes to tax contingencies as disclosed in Note 8 of the Interim Financial Statements, no material changes have occurred regarding the matters disclosed in "Note 26 - Commitments and Contingencies" of the 2018 Annual Financial Statements.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at November 6, 2019:

	Number
Common shares	97,580,803
Deferred share units ("**DSUs**") (1)	270,419
Restricted share units ("**RSUs**") (2)	1,845,472

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 DSUs 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 may be made, in 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 or achievement of personal or corporate objectives. The value of RSUs increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of an RSU holder with shareholders. Settlement may be made, in 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.

Share Repurchases

On October 16, 2019 the TSX approved the Company's notice of intention to renew its NCIB. Pursuant to the NCIB, the Company can purchase for cancellation up to 6,532,400 of its common shares during the twelve-month period commencing October 18, 2019 and ending October 17, 2020, representing approximately 10% of its public float (as such term is defined by the policies of the TSX) as at October 7, 2019. Under the prior NCIB that expired on July 17, 2019, the Company repurchased for cancellation a total of 2,684,605 Common Shares for $27.7 million.

Dividends

On December 5, 2018, the Company adopted a dividend policy that included an initial cash dividend of C$0.33 per Common Share, or $24.5 million, and targeted quarterly cash dividends of approximately $12.5 million during periods in which Brent oil prices sustain an average price of $60/bbl or higher. This policy was subsequently amended on May 30, 2019, to target quarterly cash dividends of approximately $15.0 million during periods in which Brent oil prices sustain an average price of $60/bbl or higher. The declaration and payment of any specific quarterly dividend is subject to the discretion of the Company's board of directors.

The Company´s dividends paid or declared during the nine months ended September 30, 2019, are presented below:

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

1. In connection with the adoption of the dividend policy, the Company adopted a 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.

6. RELATED-PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances outstanding and commitments with related parties, as at September 30, 2019 and December 31, 2018, and for the three and nine months ended September 30, 2019 and 2018, respectively:

($M)		Accounts Receivable	Accounts Payable	Commitments	Cash Advance (1) (2)	Long-term Receivable (1) (2)	Interest Receivable (1) (2)
ODL	2019	516	581	42,029	—	—	—
	2018	9,116	1,481	82,073	—	—	—
Bicentenario	2019	1,025	—	36,416	87,278	46,435	—
	2018	8,065	—	43,200	87,278	12,112	—
IVI	2019	—	2,708	58,631	17,741	136,191	48,137
	2018	—	1,104	123,330	17,741	123,036	37,158
CGX (3)	2018	—	—	—	—	25,945	2,186

1. Items included as other assets in Consolidated Statement of Financial Position in the Interim Financial Statements.
2. Amounts presented based on contractual payment obligations undiscounted, prior to impairments.
3. Balances shown reflect amounts before the Company acquired control of CGX on March 13, 2019. As a result, CGX is no longer a reportable related party.

($M)		Three months ended September 30 Sales	Purchases / Services	Interest Income (1)	Nine months ended September 30 Sales	Purchases / Services	Interest Income (1)
ODL	2019	—	12,366	—	—	38,050	—
	2018	—	12,572	—	1,359	34,118	—
Bicentenario	2019	—	1,441	—	—	5,116	—
	2018	—	5,344	—	—	58,142	—
IVI	2019	—	8,947	4,021	—	24,067	10,978
	2018	—	7,946	3,187	—	20,750	7,670
CGX (2)	2019	—	—	—	—	—	363
	2018	149	—	247	458	—	690
Interamerican (3)	2018	—	—	84	3	2	251

1. Amounts presented based on contractual payment obligations undiscounted, prior to impairments.
2. Balances shown reflect transactions before the Company acquired control of CGX on March 13, 2019
3. Interamerican was sold, effective October 2018 (Refer to Note 13 of the 2018 Annual Financial Statements) and was determined to no longer be a related party as at December 31, 2018.

7. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks including, but not limited to the following: operational risks such as inability to find new reserves that are commercially and economically feasible, premature declines of reservoirs, unsuccessful exploration and exploitation activities, uneconomic transportation methods, changes to environmental regulations, license and permitting issues, cybersecurity threats and other customary operating hazards and risks. The Company attempts to mitigate these risks by developing reserve development strategies, employing highly skilled employees utilizing available technology and maintaining insurance coverage that is consistent with industry practices to protect against insurable operating losses.

The Company is also 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 continuously monitors opportunities to use financial instruments to manage exposure to fluctuations in commodity prices, foreign currency rates and interest rates.

The Company considers the risks identified above as the most significant risks associated with the disclosure contained in the Interim Financial Statements and this MD&A. 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, investors are urged to review the Company's AIF and Consolidated Financial Statements as of December 31, 2018, copies of which are available on SEDAR at www.sedar.com.

8. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Interim Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook - Accounting. A summary of significant accounting policies applied is included in Note 2 of the Interim Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Effective January 1, 2019, the Company adopted IFRS 16 - Leases on a modified retrospective basis with no changes to comparative period amounts. As a result of adopting IFRS 16, the Company recognized a significant increase to both non-current assets and lease liabilities. The full effect on adoption of this new accounting standard is further described in Note 2 of the Interim Financial Statements.

The preparation of the Interim Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss and the related disclosure of contingent assets and liabilities included in the Interim Financial Statements. The Company evaluates its estimates on an ongoing basis. The estimates are based on historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. These estimates form the basis for making judgments about the carrying value of assets and liabilities and the reported amounts of revenues and other items. Actual results may differ from these estimates under different assumptions or conditions. A summary of the more significant judgments and estimates made by management in the preparation of its financial information is provided in Note 2 of the Interim Financial Statements.

9. INTERNAL CONTROL

In accordance with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Interim Filings". This Certification requires certifying officers to certify, among other things, that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Controls over Financial Reporting ("**ICFR**") as those terms are defined in NI 52-109. The control framework used to design the Company's ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations.

There have been no changes in the Company's ICFR during the quarter ended September 30, 2019, that have materially affected, or are reasonably likely to materially affect, its ICFR.

The Company's DC&P is designed to provide reasonable assurance that:

- Material information relating to the Company is made known to the Company's certifying officers by others, particularly during the period in which the interim filings are being prepared.
- Information required to be disclosed by the Company in its annual filings, interim filings and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

10. FURTHER DISCLOSURES

Production Reporting

Production volumes are reported on a Company working interest before royalties basis, including total volumes produced from service contracts. The latter refers to the total volumes produced under an oil extraction services contract with Perupetro on Block 192 in Peru. 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 49% 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	**Q3 2019**	**Q2 2019**	**Q3 2018**	**YTD 2019**	**YTD 2018**
Heavy oil	30,758	28,670	23,497	29,165	24,139
Light and medium oil	25,726	27,574	26,949	27,820	27,548
Natural gas	2,283	2,454	4,122	2,461	4,498
Net production Colombia	**58,767**	**58,698**	**54,568**	**59,446**	**56,185**
Producing blocks in Peru					
Light and medium oil	5,504	8,416	3,990	5,318	6,762
Net production Peru	**5,504**	**8,416**	**3,990**	**5,318**	**6,762**
Total net production	**64,271**	**67,114**	**58,558**	**64,764**	**62,947**

Boe Conversion

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A, boe has been expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.

Abbreviations

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

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