MANAGEMENT DISCUSSION & ANALYSIS

July 31, 2019
For the three and six months ended June 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 six months ended June 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 drilling plans, exploration activities, facilities and infrastructure projects, development drilling projects and exploration projects) 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, except as may be required by applicable securities law, the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.*

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

		Q2 2019	Q1 2019	Q2 2018	Six months ended June 30 2019	Six months ended June 30 2018
Operational Results						
Oil production	(bbl/d)	71,931	65,323	67,522	68,645	68,249
Natural gas production	(boe/d)	2,454	2,651	4,504	2,552	4,688
Production [1]	(boe/d) [2]	74,385	67,974	72,026	71,197	72,937
Oil and gas sales and other revenue	($/boe)	65.01	58.08	67.82	61.73	65.01
Realized loss on risk management contracts	($/boe)	(0.33)	(0.30)	(11.12)	(0.31)	(10.19)
Royalties	($/boe)	(2.40)	(1.74)	(2.19)	(2.09)	(1.99)
Diluent costs	($/boe)	(2.17)	(1.71)	(1.74)	(1.95)	(1.80)
Net sales realized price [3]	($/boe)	60.11	54.33	52.77	57.38	51.03
Production costs [4]	($/boe)	(11.17)	(11.40)	(12.44)	(11.28)	(11.77)
Transportation costs [5]	($/boe)	(12.49)	(12.70)	(11.81)	(12.59)	(12.25)
Operating netback [6]	($/boe)	36.45	30.23	28.52	33.51	27.01
Financial Results						
Oil and gas sales and other revenue	($M)	391,049	313,459	418,560	704,508	708,094
Realized loss on risk management contracts	($M)	(1,986)	(1,593)	(68,613)	(3,579)	(111,006)
Royalties	($M)	(14,439)	(9,376)	(13,528)	(23,815)	(21,722)
Diluent costs	($M)	(13,028)	(9,217)	(10,741)	(22,245)	(19,606)
Net sales [6]	($M)	361,596	293,273	325,678	654,869	555,760
Net income (loss) [7]	($M)	227,809	46,187	(184,436)	273,996	(187,557)
Per share – basic [8]	($)	2.32	0.47	(1.84)	2.79	(1.88)
Per share – diluted [8]	($)	2.29	0.47	(1.84)	2.75	(1.88)
General and administrative	($M)	18,207	16,492	26,168	34,699	48,221
Operating EBITDA [6]	($M)	181,159	144,855	124,667	326,014	210,655
Cash provided by operating activities	($M)	176,118	72,075	109,525	248,193	137,870
Capital expenditures [9]	($M)	73,487	69,219	86,813	142,706	165,654
Cash and cash equivalents – unrestricted	($M)	353,911	340,671	550,840	353,911	550,840
Restricted cash short and long-term	($M)	131,723	146,517	179,248	131,723	179,248
Total cash	($M)	485,634	487,188	730,088	485,634	730,088
Total debt and lease liabilities [10]	($M)	412,158	417,751	352,806	412,158	352,806

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 income (loss) attributable to equity holders of the Company.
8. The basic and diluted weighted average number of Common Shares is stated on an adjusted post-split basis.
9. Capital expenditures includes costs, net of sales from exploration and evaluation ("**E&E**") assets.
10. 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 prospective 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 Second Quarter of 2019

Financial and Operational Results

- Net income for the second quarter of 2019 was $227.8 million ($2.32/share) compared with a net loss of $184.4 million ($1.84/share) in the same period of 2018. Net income for the second quarter of 2019 includes a gain of $176.6 million from the recognition of deferred income tax from deductible temporary differences on undepreciated capital expenses related to oil and gas properties.
- Cash from operating activities was $176.1 million in the second quarter of 2019, compared to $109.5 million in the same prior year period, contributing to a total cash position of $485.6 million at June 30, 2019 (including restricted cash of $131.7 million).
- Production averaged 74,385 boe/d during the second quarter of 2019, 9% higher than the first quarter of 2019 and 3% higher than the second quarter of 2018. This increase was driven by higher production on Block 192 in Peru which was operational for most of the quarter.
- Oil and gas sales and other revenue was $391.0 million in the second quarter of 2019, a decrease of 7% compared to the same period in 2018. Net sales for the second quarter of 2019 (including the impact of realized losses on risk management contracts, royalties and diluent costs) increased by 11% compared to the second quarter of 2018.
- Operating EBITDA in the second quarter of 2019 was $181.2 million, compared to $124.7 million in the same period of 2018. The adoption of IFRS 16 increased Operating EBITDA by $5.9 million, or 5%, during the second quarter of 2019 compared to the same period of 2018, as the standard was applied prospectively on January 1, 2019.
- Operating netback in the second quarter of 2019 was $36.45/boe, 28% higher than $28.52/boe in the second quarter of 2018 and 21% higher than $30.23/boe in the first quarter of 2019. The adoption of IFRS 16 increased Operating Netback by $0.71/boe, or 2%, during the second quarter of 2019 compared to same period of 2018.
- Capital expenditures during the second quarter of 2019 were $73.5 million compared to $86.8 million in the same prior year period.

Guidance Update

- Based on the strong results from the first half of 2019 and expectations for the remainder of the year, the Company is raising its 2019 Guidance range for Operating EBITDA by 29% while reducing the range for production costs by 6%, both at the midpoint. The biggest drivers to the changes in annual guidance were improved oil price differential assumptions as well as the impact of a weaker COP relative to previous estimates. All other guidance metrics remain unchanged.

Portfolio Enhancements

- The Company was awarded the Llanos-99 block and VIM-22 block in Colombia following the successful Agencia Nacional de Hidrocarburos ("**ANH**") bid round. The Company signed the agreements on July 18, 2019.

Shareholder Value Initiatives

- During the quarter, the Company increased its quarterly dividend and paid $15.4 million (C$0.205/share) on July 17, 2019 to shareholders of record on July 3, 2019, which included the issuance of 244 Common Shares to shareholders electing to participate in the Company's Dividend Reinvestment Plan ("**DRIP**"). As at July 31, 2019, the Company has paid total dividends of $52.0 million to shareholders for the year, including the issuance of 628,560 Common Shares under the DRIP.
- During the second quarter of 2019, the Company repurchased for cancellation 151,500 Common Shares for $1.3 million under its Normal Course Issuer Bid ("**NCIB**") that expired on July 17, 2019. Under the NCIB, which commenced on July 18, 2018, the Company has repurchased for cancellation a total of 2,684,605 Common Shares for $27.7 million. The Company anticipates that it will renew its NCIB, subject to the approval of the Toronto Stock Exchange, during the third quarter of 2019.

2. GUIDANCE

The Company has increased its annual Operating EBITDA guidance by 29% at the midpoint to $525-$575 million from $400-$450 million as a result of changes in the assumptions used for realized oil price differentials and foreign exchange, in addition to the lowering of production cost guidance, discussed below. The most significant factor impacting higher Operating EBITDA is the stronger than expected oil price differentials during the year that have resulted in lowering this assumption for 2019 to $3.50/bbl compared to $8.40/bbl in the original guidance.

Guidance for production costs per boe was reduced by 6% to a midpoint value of $12.25/boe (from $13.00/boe) to reflect year-to-date results, which have trended lower as a result of a weaker COP, periods of suspended production at Block 192 in Peru and better than expected production in Colombia. The Company expects production costs per boe to increase during the second half of 2019 assuming more consistent production from Block 192.

Annual guidance ranges for production, net production, transportation costs per boe and capital expenditures remain unchanged. The following table reports the Company's actual results for the six months period ending June 30, 2019, against the revised and previous guidance.

		2019 Guidance (1)		
		Revised (2)	2019 YTD	Previous (3)
Average production	(boe/d)	65,000 to 70,000	71,197	65,000 to 70,000
Average net production	(boe/d)	60,000 to 65,000	65,015	60,000 to 65,000
Production costs	($/boe)	12.00 to 12.50	11.28	12.50 to 13.50
Transportation costs	($/boe)	12.50 to 13.50	12.59	12.50 to 13.50
Operating EBITDA	($MM)	525 to 575	326	400 to 450
Capital expenditures	($MM)	325 to 375	143	325 to 375

1. The guidance for operating EBITDA and capital expenditures are aggregate ranges for the year.
2. Revised guidance assumes $65.00/bbl Brent, and realized oil price differential of $3.50/bbl and foreign exchange rate of 3,100 COP to 1 USD.
3. Previous guidance was released on December 6, 2018 assuming $65.00/bbl Brent, realized oil price differentials of $8.40/bbl and foreign exchange rate of 3,000 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.

	Average Production (in boe/d)				
Producing blocks in Colombia	**Q2 2019**	**Q1 2019**	**Q2 2018**	**YTD 2019**	**YTD 2018**
Light and medium oil	29,494	32,394	30,814	30,936	30,097
Heavy oil	32,462	30,658	28,294	31,565	28,583
Natural gas	2,454	2,651	4,504	2,552	4,688
Total production Colombia	**64,410**	**65,703**	**63,612**	**65,053**	**63,368**
Producing blocks in Peru					
Light and medium oil	9,975	2,271	8,414	6,144	9,569
Total production Peru	**9,975**	**2,271**	**8,414**	**6,144**	**9,569**
Total production	**74,385**	**67,974**	**72,026**	**71,197**	**72,937**

Colombia

Production in Colombia for the three and six months ended June 30, 2019, increased by 1% to 64,410 boe/d and by 3% to 65,053 boe/d, respectively, compared to the same periods of 2018. Higher production was a result of the drilling campaign and higher volumes from Quifa block due to the water handling capacity and its system optimization. These increases helped to offset production declines from mature blocks in the light and medium oil and natural gas blocks.

In comparison to the first quarter of 2019, production was 2% or 1,293 boe/d lower during the second quarter of 2019 reflecting the impact of the managed decline from the Candelilla-7 well on the Guatiquia block.

Peru

Production in Peru for the second quarter of 2019 averaged 9,975 boe/d, an increase of 19% or 1,561 boe/d compared with the same quarter of 2018. For the six months ended June 30, 2019, average production decreased by 36% to 6,144 boe/d from 9,569 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 events on the pipeline have caused the Company to shut down production on the block.

In comparison to the first quarter of 2019, production was 7,704 boe/d higher during the second quarter of 2019, reflecting consistent operations at Block 192 for the majority of the quarter.

On June 18, 2019, the Company was notified by Petroperú S.A. ("**Petroperú**"), the operator of the NorPeruano pipeline, of a force majeure event affecting a portion of the pipeline as a result of an attack. Due to a community dispute, Petroperú was not permitted to conduct activities necessary to resume pumping oil through the pipeline which caused the Company to shut down production from Block 192 on July 1, 2019. Effective July 30, 2019, repairs were completed on the NorPeruano pipeline and the Company resumed normal operations, allowing it to restart production from Block 192.

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.

					Six months ended June 30	
		Q2 2019	Q1 2019	Q2 2018	2019	2018
Production	**(boe/d)**	**74,385**	**67,974**	**72,026**	**71,197**	**72,937**
Royalties in-kind Colombia	(boe/d)	(5,712)	(4,806)	(6,667)	(5,262)	(6,361)
Royalties in-kind Peru (1)	(boe/d)	(1,559)	(275)	(1,219)	(920)	(1,398)
Net production	**(boe/d)**	**67,114**	**62,893**	**64,140**	**65,015**	**65,178**
Oil inventory draw (build)	(boe/d)	1,369	962	1,521	1,167	(2,856)
(Settlement) overlift positions	(boe/d)	(13)	—	3,493	(7)	184
Sales volumes from E&E assets (2)	(boe/d)	(37)	(63)	(979)	(50)	(1,073)
Other inventory movements (3)	(boe/d)	(2,328)	(3,824)	(353)	(3,072)	(1,259)
Sales volumes	**(boe/d)**	**66,105**	**59,968**	**67,822**	**63,053**	**60,174**
Oil sales volumes	(bbl/d)	63,794	57,363	63,283	60,596	55,508
Natural gas sales volumes	(boe/d)	2,311	2,605	4,539	2,457	4,666
Inventory balance						
Colombia	(bbl)	454,909	518,857	54,292	454,909	54,292
Peru	(bbl)	1,395,343	1,456,054	1,401,511	1,395,343	1,401,511
Inventory ending balance	**(bbl)**	**1,850,252**	**1,974,911**	**1,455,803**	**1,850,252**	**1,455,803**

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 below.
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.

Colombia Royalties - PAP

The Company makes high-price clause participation ("**PAP**") payments to Ecopetrol S.A. and the ANH 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 US Producer Price Index ("**PPI**"). Increases in oil prices trigger higher PAP obligations payable both in-kind (reducing the Company's net production) and in cash (increasing royalties).

The Company paid approximately 3.1% (combined cash and in-kind) of its production in the second quarter of 2019 as PAP, which was lower than 4.4% paid in the same period of 2018 and higher than 1.7% paid in the previous quarter. The Company paid PAP in-kind volumes averaging 1,036 bbl/d during the second quarter of 2019, compared with 2,050 bbl/d in the same quarter of 2018, and 83 bbl/d in the first quarter of 2019.

During the six months ended June 30, 2019, the Company paid approximately 2.4% (combined cash and in-kind) of its production as PAP, which was lower than 3.8% paid in the same period of 2018. The Company paid PAP in-kind volumes averaging 563 bbl/d during the six months ended June 30, 2019, compared with 1,708 bbl/d in the same period of 2018.

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, which is 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 June 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 1,559 bbl/d and 920 bbl/d, respectively, during the three and six months ended June 30, 2019, compared with 1,581 bbl/d and 2,799 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.

Realized and Reference Prices

					Six months ended June 30	
		Q2 2019	**Q1 2019**	**Q2 2018**	**2019**	**2018**
Reference price						
Brent	($/bbl)	68.47	63.83	74.97	66.17	71.16
Average realized prices						
Realized oil price	($/bbl)	66.45	59.70	70.44	63.27	67.45
Realized natural gas price	($/boe)	19.14	19.05	23.10	19.09	23.18
Other revenue [(1)]	($/boe)	0.21	0.15	0.55	0.18	0.99
Net sales realized price						
Oil and gas sales and other revenue	($/boe)	65.01	58.08	67.82	61.73	65.01
Realized loss on risk management contracts	($/boe)	(0.33)	(0.30)	(11.12)	(0.31)	(10.19)
Royalties	($/boe)	(2.40)	(1.74)	(2.19)	(2.09)	(1.99)
Diluent costs	($/boe)	(2.17)	(1.71)	(1.74)	(1.95)	(1.80)
Net sales realized price	**($/boe)**	**60.11**	**54.33**	**52.77**	**57.38**	**51.03**

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 second quarter and first half of 2019 were lower by 9% and 7%, 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 and increased oil supply leading to higher than expected crude oil inventories. 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. In comparison to the first quarter of 2019, crude oil prices improved with the Brent benchmark price increasing by an average of 7%, or $4.64/bbl, during the second quarter of 2019 as oil producing blocks, such as the Organization of Petroleum Exporting Countries, continued to limit production to offset rising global inventory levels.

For the three and six months ended June 30, 2019, the Company's net sales realized price was $60.11/boe and $57.38/boe, respectively, an increase of 14% and 12% compared to the same periods of 2018 mainly due to significantly lower realized losses from risk management contracts compared to prior periods. Refer to the "Gain (Loss) on Risk Management Contracts" section on page 11. In comparison to the first quarter of 2019, the net sales realized price increased by 11%, or $5.78/boe, which was primarily driven by the related increase in the benchmark oil price.

Operating Netback

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

	Q2 2019		Q1 2019		Q2 2018	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	361,596	60.11	293,273	54.33	325,678	52.77
Production costs (2)	(75,598)	(11.17)	(69,758)	(11.40)	(81,520)	(12.44)
Transportation costs (3)	(76,260)	(12.49)	(71,906)	(12.70)	(68,935)	(11.81)
Operating Netback (4)	**209,738**	**36.45**	**151,609**	**30.23**	**175,223**	**28.52**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes (D&P) (5)		66,105		59,968		67,822
Production (6)		74,385		67,974		72,026
Net production (6)		67,114		62,893		64,140

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) 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.

Operating netback for the second quarter of 2019 was $36.45/boe compared to $28.52/boe in the same quarter of 2018. The increase was primarily due to a higher net sales realized price and lower production costs per boe in the current quarter. Although benchmark oil prices were lower in the second quarter of 2019, the Company had hedging positions in the comparable quarter of 2018 that limited the upside, resulting in higher realized loss from risk management contracts. Production costs per boe decreased due to fewer workovers, well services and maintenance activities and lower personnel-related costs as a result of cost saving initiatives during 2018. These factors were partially offset by higher transportation costs per boe due to sales in Peru from the reactivation of Block 192 during the second quarter of 2019.

In comparison to the first quarter of 2019, operating netback increased by 21% primarily as a result of a higher net sales realized price from lower realized loss on risk management contracts for the same reasons described above.

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

	Six months ended June 30			
	2019		**2018**	
	$M	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	654,869	57.38	555,760	51.03
Production costs (2)	(145,356)	(11.28)	(155,399)	(11.77)
Transportation costs (3)	(148,166)	(12.59)	(144,513)	(12.25)
Operating Netback (4)	**361,347**	**33.51**	**255,848**	**27.01**
		(boe/d)		**(boe/d)**
Sales volumes (D&P) (5)		63,053		60,174
Production (6)		71,197		72,937
Net production (6)		65,015		65,178

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

Operating netback for the six months ended June 30, 2019, increased by 24% to $33.51/boe from $27.01/boe in the same period of 2018. The increase was primarily due to a higher net sales realized price and lower production costs due to fewer workovers, well services and maintenance activities and lower personnel-related costs as a result of cost saving initiatives during 2018. Additionally, transportation costs per boe increased mainly due to higher volumes sold from Block 192 during the six months ended June 30, 2019.

Sales

($M)	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
Oil and gas sales and other revenue (1)	391,049	418,560	704,508	708,094
Realized loss on risk management contracts	(1,986)	(68,613)	(3,579)	(111,006)
Royalties	(14,439)	(13,528)	(23,815)	(21,722)
Diluent costs	(13,028)	(10,741)	(22,245)	(19,606)
Net sales	**361,596**	**325,678**	**654,869**	**555,760**
$/boe using sales volumes from D&P assets	60.11	52.77	57.38	51.03

1. In Colombia, for the three and six months ended June 30, 2019, oil and gas sales and other revenue were $338.6 million and $647.6 million compared with $401.8 million and $650.2 million, respectively, in the same periods of 2018. In Peru, for the three and six months ended June 30, 2019, oil and gas sales and other revenue were $52.4 million and $56.9 million, compared with $16.8 million and $57.9 million, respectively, in the same periods of 2018.

Oil and gas and other revenue for the three months ended June 30, 2019, decreased by $27.5 million compared to the same period in 2018, mainly due to lower oil and gas prices and volume sold. Oil and gas and other revenue for the six months ended June 30, 2019, decreased by $3.6 million compared to the same period in 2018, mainly due to lower oil and gas prices.

Net sales for the three and six months ended June 30, 2019, increased by $35.9 million and $99.1 million, respectively, compared with the same periods in 2018. The following table describes the various factors that impacted net sales:

($M)	Three months ended June 30	Six months ended June 30
	2019-2018	2019-2018
Net sales for the period ended June 30, 2018	325,678	555,760
Decrease due to 4% lower oil and gas price (YTD lower 5%)	(16,914)	(37,463)
Lower realized loss on risk management contracts	66,627	107,427
Increase in royalties	(911)	(2,093)
Decrease due to lower volumes sold of 1,717 boe/d or 3% (YTD higher 2,879 boe/d or 5%)	(10,597)	33,877
Increase in diluent costs	(2,287)	(2,639)
Net sales for the period ended June 30, 2019	**361,596**	**654,869**

Royalties

($M)	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
Cash royalties Colombia	14,257	13,371	23,413	21,314
Cash royalties Peru	182	157	402	408
Royalties	**14,439**	**13,528**	**23,815**	**21,722**
$/boe using sales volumes from D&P assets	2.40	2.19	2.09	1.99

Royalties include PAP payments, cash royalties and amounts paid to previous owners of certain blocks in Colombia. For the three and six months ended June 30, 2019, royalties increased by $0.9 million and $2.1 million, respectively, compared to the same periods in 2018, primarily due to higher production from the Guatiquia block in Colombia. The Company's royalty burden is directly correlated with changes in benchmark WTI oil 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

	Three months ended June 30		Six months ended June 30	
($M)	**2019**	**2018**	**2019**	**2018**
Production costs	75,598	81,520	145,356	155,399
Transportation costs	76,260	68,935	148,166	144,513
Diluent costs	13,028	10,741	22,245	19,606
Inventory valuation	10,652	1,852	3,580	(7,961)
(Settlement) overlift	(25)	22,539	(5)	5,520
Total oil and gas operating costs	**175,513**	**185,587**	**319,342**	**317,077**

Total oil and gas operating costs for the three months ended June 30, 2019, decreased by 5%, or $10.1 million compared to the same period in 2018. Total oil and gas operating costs for the six months ended June 30, 2019, increased by 1%, or $2.3 million, compared to the same period in 2018. Total oil and gas operating costs changed mainly due to the following:

- Transportation costs increased by 11% and 3% in the three and six months ended June 30, 2019, respectively, compared with the same periods of 2018 primarily due to higher sales volumes transported from the reactivation of Block 192 in Peru. This increase was partially offset by lower costs from the acquisition of transportation capacity rights on the Oleoducto Central S.A. pipeline. Effective April 1, 2019, the Company reacquired these rights for gross acquisition cost of $68.5 million, which eliminated the monthly premium of $1.5 million.

- Production costs decreased by 7% and 6% in the three and six months ended June 30, 2019, respectively, compared with the same periods of 2018 mainly as a result of fewer workovers, well services and maintenance activities and lower personnel-related costs as a result of cost saving initiatives during 2018.

- Diluent costs increased by 21% and 13% for the three and six months ended June 30, 2019, respectively, mainly due to a change in blending operations during the quarter as the Company took advantage of market opportunities to purchase more diluent.

- (Settlement) overlift decreased due to no overlift positions during the first half of 2019. During the comparable periods in 2018, the Company sold more volumes than it produced resulting in the recognition of an overlift charge to offset the related sales during the periods.

- For the three and six months ended June 30, 2019, inventory valuation increased to $10.7 million and $3.6 million, respectively, compared to the same periods of 2018, due to the drawdown of crude oil inventories primarily related to the reactivation and sales at Block 192 in Peru.

Other selected operating costs

	Three months ended June 30		Six months ended June 30	
($M)	**2019**	**2018**	**2019**	**2018**
Fees paid on suspended pipeline capacity	—	40,835	—	76,739

Fees paid on suspended pipeline capacity were $Nil for the three and six months ended June 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.

General and Administrative

	Three months ended June 30		Six months ended June 30	
($M)	**2019**	**2018**	**2019**	**2018**
General and administrative	18,207	26,168	34,699	48,221

General and administrative expenses for the three and six months ended June 30, 2019, decreased by 30% and 28%, 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 six months ended June 30, 2019, of $1.5 million and $2.9 million, respectively, due to the adoption of IFRS 16.

Depletion, Depreciation and Amortization

($M)	Three months ended June 30 2019	Three months ended June 30 2018	Six months ended June 30 2019	Six months ended June 30 2018
Depletion, depreciation and amortization	99,092	85,576	192,238	158,249

Depletion, depreciation and amortization expense ("**DD&A**") increased by 16% and 21% for the three and six months ended June 30, 2019, respectively, compared to the same periods in 2018. The increase was primarily due to higher oil production in Colombia 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 six months ended June 30, 2019, the depreciation relating to the ROU assets resulted in increases of $6.3 million and $12.1 million, respectively.

Impairment

($M)	Three months ended June 30 2019	Three months ended June 30 2018	Six months ended June 30 2019	Six months ended June 30 2018
Impairment of exploration and evaluation assets	9,664	2,007	9,664	2,007
Other Impairment	4,158	269	4,158	269
Impairment of investment in associates	—	107,660	—	118,876
Impairment of PEL power transmission line assets	—	—	—	9,125
Total impairment	**13,822**	**109,936**	**13,822**	**130,277**
Exploration - pre-licence costs	1,494	—	1,494	—
Expense of asset retirement obligations	1,547	—	1,547	—
Exploration expense and other	**3,041**	**—**	**3,041**	**—**
Total impairment, exploration expense and other	**16,863**	**109,936**	**16,863**	**130,277**

For the three and six months ended June 30, 2019, the Company recognized an impairment charge of $9.7 million of exploration and evaluation assets mainly due to technical results and changes in development plans for certain exploration projects from Colombia. Additionally, the Company recognized an impairment charge of $4.2 million mainly related to slow moving or obsolete inventories.

For the three months ended June 30, 2018, the Company recognized an impairment charge of $107.7 million on the investment in Bicentenario after it exercised its right to terminate existing contracts to transport crude oil through the Bicentenario pipeline ("**BIC pipeline**"). The impairment is primarily driven by reduced volumes, revenues and related cash flows associated with the Company's terminated ship-or-pay commitments on Bicentenario. For the six months ended June 30, 2018, the Company also 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 June 30 2019	Three months ended June 30 2018	Six months ended June 30 2019	Six months ended June 30 2018
Finance income	5,469	5,120	11,502	10,684
Finance expenses	(14,644)	(14,619)	(28,322)	(24,430)
Foreign exchange gain (loss)	1,681	(8,199)	2,283	10,806
Other (loss) income, net	(497)	(699)	10,797	(1,303)

Finance Income and Expenses

Finance income and expenses includes interest on the Company's long-term debt, leases liabilities and fees on letters of credit, net of interest income received. For the three and six months ended June 30, 2019, compared with the same periods of 2018 finance income remained relatively constant. For the three and six months ended June 30, 2019, finance expenses increased to $14.6 million and $28.3 million, from $14.6 million and $24.4 million in the same periods of 2018, primarily due to interest on lease liabilities recognized on the adoption of IFRS 16.

Foreign Exchange Gain (Loss)

For the three and six months ended June 30, 2019, foreign exchange gain was $1.7 million and $2.3 million, respectively, compared with a loss of $8.2 million and a gain of $10.8 million in the same periods of 2018, primarily due to the impact of the COP's depreciation and appreciation against the USD on the translation of the Company's net working capital balances.

Other (Loss) Income, net

For the three months ended June 30, 2019, other loss was $0.5 million compared with a loss of $0.7 million in the same period of 2018, remaining relatively constant. For the six months ended June 30, 2019, other income was $10.8 million compared with a loss of $1.3 million in the same prior year period, primarily related to a gain of $10.9 million on CGX Energy Inc ("**CGX**") fair value acquisition measurement.

Gain (Loss) on Risk Management Contracts

	Three months ended June 30		Six months ended June 30	
($M)	**2019**	**2018**	**2019**	**2018**
Realized loss on risk management contracts [1]	(1,986)	(68,613)	(3,579)	(111,006)
Unrealized gain (loss) on risk management contracts [2]	6,460	(3,198)	273	14,115
Total gain (loss) on risk management contracts	**4,474**	**(71,811)**	**(3,306)**	**(96,891)**

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

For the three and six months ended June 30, 2019, realized loss on risk management contracts was $2.0 million and $3.6 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 half of 2019, Brent oil put options expired (which limited the loss to the premiums paid) compared to the first half of 2018 when zero cost collars were settled at prices that were significantly higher than average ceiling prices. Refer further to the risk management strategy described in the section "Risk Management Contracts - Brent Crude Oil" below.

For the three and six months ended June 30, 2019, the Company recognized an unrealized gain on risk management contracts of $6.5 million and $0.3 million, respectively, due to the decrease in the crude oil benchmark forward prices over the contract periods. This compared to an unrealized loss of $3.2 million in the second quarter of 2018 and an unrealized gain of $14.1 million in the first half of 2018, which was 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 comparison 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 puts.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads $**	**Assets**	**Liabilities**
Put options	July 2019 to March 2020	Brent	3,826,000	57.62	7,400	—
Zero cost collars	August 2019 to March 2020	Brent	2,531,000	57.64 / 75.66	3,496	—
Three-way collar	April 2020 to June 2020	Brent	240,000	45.00 / 55.00 /74.26	16	9
Total as at June 30, 2019					10,912	9
Put options	January 2019 to September 2019	Brent	2,220,000	55.00	9,380	—
Total as at December 31, 2018					9,380	—

During July 2019, the Company continued with its hedging program, adding the following positions subsequent to June 30, 2019, as follows:

				Avg. Strike Prices
Type of Instrument	Term	Benchmark	Notional Amount / Volume (bbl)	Put/ Call; Call Spreads
Put spreads	January 2020 to March 2020	Brent	240,000	47-57
Three-way collar	April 2020 to June 2020	Brent	540,000	45-55-74.49
Total			780,000	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. The Company monitors its exposure to such foreign currency risks. As at June 30, 2019, the Company has entered into foreign currency derivatives contracts from July 2019 to December 2019, for $121.5 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 $MM	Avg. Put / Call; Par forward COP	Assets	Liabilities
Zero cost collars	July 2019 to December 2019	COP / USD	$	121,500	3,092 / 3,479	2	—
Total as at June 30, 2019						**2**	**—**
Zero cost collars	January 2019 to June 2019	COP / USD	$	172,500	3,032 / 3,273	—	3,299
Forward	January 2019 to March 2019	COP / USD	$	22,500	3,109	—	1,019
Total as at December 31, 2018						**—**	**4,318**

Income Tax Expense

	Three months ended June 30		Six months ended June 30	
($M)	**2019**	**2018**	**2019**	**2018**
Current income tax expense	(5,394)	(5,454)	(8,927)	(15,783)
Deferred income tax recovery (expense)	162,166	(6,271)	144,013	(6,688)
Total income tax expense	**156,772**	**(11,725)**	**135,086**	**(22,471)**

The current income tax expense for the second quarter of 2019 was $5.4 million, which included minimum income taxes (presumptive tax) of $5.4 million.

In addition, a deferred income tax asset in the amount of $176.6 million has been recorded in Colombia, offset by an income tax expense of $32.6 million related to the utilization of the prior deferred tax asset. The deferred income tax asset consists of deductible temporary differences that arose primarily from undepreciated capital expenses related to oil and gas properties. Projections of taxable profits were used to support the deferred tax recognition. Future projected income could be affected by oil prices and quantities of proved and probable reserves. If these factors or other circumstances change, the Company will reassess its ability to record any increase or decrease in its deferred income tax asset.

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

Net Income (Loss)

	Three months ended June 30		Six months ended June 30	
($M)	**2019**	**2018**	**2019**	**2018**
Net income (loss) attributable to equity holders of the Company	227,809	(184,436)	273,996	(187,557)
Per share – basic	2.32	(1.84)	2.79	(1.88)
Per share – diluted	2.29	(1.84)	2.75	(1.88)

For the three months ended June 30, 2019, the Company reported a net income of $227.8 million, which includes a gain relating to the recognition of a deferred income tax benefit of $162.2 million. This compares to a net loss of $184 million in the second quarter of 2018, which resulted from certain charges, including an impairment expense of $107.7 million on the investment in Bicentenario, $71.8 million of losses from risk management contracts, and one-time losses from debt restructuring of $25.6 million and reclassification of cumulative translation adjustments on the disposal of PEL of $50.8 million. In addition, the Company no longer incurs fees paid on suspended pipeline capacity compared with a $40.8 million expense during the second quarter of 2018.

For the six months ended June 30, 2019, the Company reported a net income of $274.0 million, compared to a net loss of $187.6 million in the second quarter of 2018. The main items impacting this change are similar to the quarterly variances described in the prior paragraph.

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
($M)	**2019**	**2018**	**2019**	**2018**
Maintenance and development drilling	47,833	39,350	100,700	83,133
Exploration activities [1]	15,920	27,660	24,180	52,496
Facilities and infrastructure	8,253	15,857	15,889	23,512
Administrative assets and other projects	1,481	3,946	1,937	6,513
Total capital expenditures	**73,487**	**86,813**	**142,706**	**165,654**

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

Capital expenditures for the three and six months ended June 30, 2019 were $73.5 million and $142.7 million, 15% and 14% lower, respectively, compared to the same periods of 2018 as a result of lower exploration expenditures due to the higher cost wells drilled during 2018. A total of 41 development wells and three exploration wells were drilled and completed during second quarter of 2019, compared to 23 development wells and one exploration well in the second quarter of 2018. For the six months ended June 30, 2019, a total of 68 development wells and five exploration wells were drilled, compared to 50 development wells and three exploration wells drilled in the same period of 2018. The Company continued to invest in exploration and development drilling with eight rigs in operation during the second quarter of 2019, including five in the Quifa heavy oil block, and three in the light oil-focused blocks (Guatiquia, Cubiro and Mapache blocks).

Selected Quarterly Information

Operational and financial results		2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3
Oil production	(bbl/d)	71,931	65,323	68,661	62,271	67,522	68,983	64,559	71,984
Natural gas production	(boe/d)	2,454	2,651	3,263	4,122	4,504	4,875	5,315	5,427
Production	(boe/d)	74,385	67,974	71,924	66,393	72,026	73,858	69,874	77,411
Oil and gas natural gas sales volumes	(boe/d)	66,105	59,968	50,298	61,071	67,822	52,440	65,481	63,162
Brent price	($/bbl)	66.17	63.83	68.60	75.84	74.97	67.23	61.46	52.17
Oil and gas sales and other revenue	($/boe)	65.01	58.08	60.06	68.02	67.82	61.34	56.19	47.55
Realized loss (gain) on risk management contracts	($/boe)	(0.33)	(0.30)	(5.55)	(10.02)	(11.12)	(8.98)	(2.93)	0.31
Royalties	($/boe)	(2.40)	(1.74)	(2.94)	(2.83)	(2.19)	(1.74)	(1.35)	(0.81)
Diluent costs	($/boe)	(2.17)	(1.71)	(2.22)	(1.89)	(1.74)	(1.88)	(1.00)	(1.21)
Net sales realized price	($/boe)	60.11	54.33	49.35	53.28	52.77	48.74	50.91	45.84
Production costs	($/boe)	(11.17)	(11.40)	(12.76)	(13.84)	(12.44)	(11.11)	(11.98)	(9.87)
Transportation costs	($/boe)	(12.49)	(12.70)	(12.89)	(13.77)	(11.81)	(12.68)	(14.28)	(11.77)
Operating netback	($/boe)	36.45	30.23	23.70	25.67	28.52	24.95	24.65	24.20
Revenue [1]	($M)	377,347	377,527	265,109	366,511	405,198	283,667	344,862	300,574
Net income (loss)	($M)	227,809	46,187	(116,631)	45,105	(184,436)	(3,121)	(32,544)	(141,115)
Per share – basic	($)	2.32	0.47	(1.17)	0.45	(1.84)	(0.03)	(0.33)	(1.41)
Per share – diluted	($)	2.29	0.47	(1.17)	0.45	(1.84)	(0.03)	(0.33)	(1.41)
General and administrative	($M)	18,207	16,492	21,839	22,962	26,168	22,053	24,450	26,569
Operating EBITDA	($M)	181,159	144,855	118,398	93,455	124,667	85,988	104,316	110,243
Capital expenditures	($M)	73,487	69,219	156,400	124,029	86,813	78,841	111,213	48,563

1. 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, movements in the Brent benchmark oil price, fluctuations in oil price differentials and realized gains and losses arising from risk management activities. Trends in the Company's production levels in Colombia have resulted from natural declines on existing fields and suspension of operations due to unforeseen circumstances, such as community blockades, partially offset by increased investment in the capital expenditures program. The Company has had fluctuating production in Peru since operations at Block 192 have experienced periods of suspension under force majeure due to pipeline issues. 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, changes in unrealized gains and losses from risk management activities that fluctuate with changes in 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 in the Company's midstream interests.

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 six months ended June 30, 2019, the Company's share of income from ODL increased by $6.5 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 six months ended June 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 BIC pipeline that runs from the Araguaney Station in Casanare Department to the Banadia Station in 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 Sucre Department.

On March 22, 2019, the Company increased its net ownership interest (after non-controlling interest) in Bicentenario from 26.4% to the current 43.0% through the acquisition of PML's ownership interest in Bicentenario for approximately $84.8 million. The International Financial Corporation and related funds triggered this acquisition as a result of the termination of the Company's take or pay contracts 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 six months ended June 30, 2019, the Company's share of income from Bicentenario decreased by $17.2 million as 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 six months ended June 30, 2019, the Company recognized gross dividends of $17.5 million, which were declared but not paid by Bicentenario. As at June 30, 2019, the Company has accounts receivables of $30.5 million in dividends from Bicentenario. The timing of dividend payments is uncertain.

Infrastructure Ventures Inc. ("IVI") (formerly Pacific Infrastructure Ventures Inc. "PIV")

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, one of the largest trade hubs in Latin America. 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 deficiency notice, requiring it 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, when it is determined that there are certain deficiencies related to operation and maintenance of the port facility and Puerto Bahia's ability to make payments towards its bank debt obligations. 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 to Puerto Bahia under the ECA (of which $30.1 million is currently overdue).

For the six months ended June 30, 2019, the Company has additional loans receivable from IVI of $10.9 million compared to $30.5 million for the same period of 2018, in aggregate principal, with a balance of $99.5 million as at June 30, 2019 compared to $88.0 as at June 30, 2018. The loans bear interest that ranges from LIBOR+3.0% to 10.0% per annum.

For six months ended June 30, 2019, the Company's share of loss from IVI increased $2.9 million compared to the same period of 2018, mainly due to higher unrealized loss on the revaluation of USD denominated debt compared to the prior period.

The Company's consolidated statements of income and cash flows includes the following amounts relating to these investments:

Statements of Income	Six months ended June 30									
	2019					2018				
($M)	PML	ODL	Bicentenario	IVI	Total	PML	ODL	Bicentenario	IVI	Total
Share of income from associates	—	28,480	18,705	(3,934)	43,251	—	22,012	35,869	(1,002)	56,879
Impairment	—	—	—	—	—	—	—	(114,605)	—	(114,605)
Finance income	649	—	191	4,555	5,395	135	—	—	1,853	1,988
G&A	(864)	—	(18)	(4)	(886)	(2,094)	—	—	(5)	(2,099)
Income tax [1]	(3,321)	—	—		(3,321)	(2,630)	—	—	—	(2,630)
Other income (expenses)	76		—	—	76	(5,306)	—	—	—	(5,306)
(Income) loss attributable to non-controlling interest [2]	(8,300)	—	—	—	(8,300)	7,943	—	—	—	7,943

1. Income tax mainly related to Bicentenario and ODL dividends.
2. Includes Petroelectrica minority interest for 2018.

Statements of Cash Flows	Six months ended June 30									
	2019					2018				
($M)	PML	ODL	Bicentenario[1]	IVI	Total	PML	ODL	Bicentenario	IVI	Total
Dividends received from associates	—	32,704	—	—	32,704	—	20,931	27,966	—	48,897
Dividends paid to non-controlling interest	—	(12,515)	—	—	(12,515)	—	(7,627)	(10,191)	—	(17,818)
Additions to other assets [2]	—	—	—	(10,900)	(10,900)	—	—	—	(30,461)	(30,461)
Total	**—**	**20,189**	**—**	**(10,900)**	**9,289**	**—**	**13,304**	**17,775**	**(30,461)**	**618**

1. Excludes dividends paid to non-controlling interest related to the put option.
2. Includes new loans or equity paid to associates.

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 therefore are unlikely to be comparable to similar measures presented by other companies. Furthermore, these non-IFRS measures should not be considered in isolation or as a substitute for measures of performance or cash flows as prepared in accordance with IFRS.

Operating EBITDA

EBITDA is a commonly used measure that adjusts net income (loss) as reported under IFRS to exclude the effects of income 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 income (loss) to operating EBITDA:

($M)	Three months ended June 30 2019	Three months ended June 30 2018	Six months ended June 30 2019	Six months ended June 30 2018
Net income (loss)	227,809	(184,436)	273,996	(187,557)
Fees paid on suspended pipeline capacity	—	40,835	—	76,739
Share-based compensation	1,145	1,780	1,717	2,834
Depletion, depreciation and amortization	99,092	85,576	192,238	158,249
Impairment and exploration expenses	16,863	109,936	16,863	130,277
Restructuring, severance and other costs	2,048	1,554	3,488	4,392
Share of income from associates	(19,753)	(19,651)	(43,251)	(55,410)
Foreign exchange (gain) loss	(1,681)	8,199	(2,283)	(10,806)
Finance income	(5,469)	(5,120)	(11,502)	(10,684)
Finance expenses	14,644	14,619	28,322	24,430
Unrealized (gain) loss on risk management contracts	(6,460)	3,198	(273)	(14,115)
Other loss (income), net	497	699	(10,797)	1,303
Loss on extinguishment of debt	—	25,628	—	25,628
Income tax (recovery) expense	(156,772)	11,725	(135,086)	22,471
Non-controlling interests	9,196	(20,722)	12,582	(7,943)
Reclassification of currency translation adjustments	—	50,847	—	50,847
Operating EBITDA	**181,159**	**124,667**	**326,014**	**210,655**

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 dilution, the cost of which is partially recovered when the blended product is sold. Net sales does 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 June 30 2019	Three months ended June 30 2018	Six months ended June 30 2019	Six months ended June 30 2018
Net sales ($M)	361,596	325,678	654,869	555,760
Denominator				
Sales volumes (D&P) - (boe)	6,015,555	6,171,802	11,412,593	10,891,494
Net sales realized price ($/boe)	60.11	52.77	57.38	51.03

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

	Three months ended June 30		Six months ended June 30	
	2019	**2018**	**2019**	**2018**
Production costs ($M)	75,598	81,520	145,356	155,399
Denominator				
Production (boe)	6,769,055	6,554,372	12,886,703	13,201,653
Production costs ($/boe)	11.17	12.44	11.28	11.77

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

	Three months ended June 30		Six months ended June 30	
	2019	**2018**	**2019**	**2018**
Transportation costs ($M)	76,260	68,935	148,166	144,513
Denominator				
Net production (boe)	6,107,378	5,836,739	11,767,758	11,797,159
Transportation costs ($/boe)	12.49	11.81	12.59	12.25

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 June 30, 2019, the Company had total cash balances of $485.6 million (including restricted cash of $131.7 million), a decrease of $102.8 million as compared to the prior year-end, primarily due to $30.8 million of dividends paid to equity holders of the Company, $9.9 million related to share repurchases from equity holders, $12.0 million of lease payments and $48.5 million related to the acquisition of Transporte Incorporado's transportation capacity rights related to the Oleoducto Central S.A. pipeline.

As at June 30, 2019, total cash balances include short and long-term restricted cash of $131.7 million, a decrease of $10.6 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 stand by letter of credit ("**SBLC's**"), releasing the restricted cash that was a guarantee for an abandonment obligation.

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 June 30, 2019, the Company had a working capital surplus of $176.0 million, a decrease of $39.7 million as compared to 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 June 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 June 30, 2019, in addition to letters of credit issued from the Unsecured LC Facility of $37.1 million, the Company has also issued $0.9 million of cash collateralized letters of credit. During the second quarter 2019, the Company was granted two new credit lines for a total of $22.2 million, under which some letters of credit were issued to guarantee exploratory and abandonment commitments of $21.6 million and $14.4 million, respectively; in both cases, the lenders under these new credit lines receive a fee equal to 3.0% per annum. As at June 30, 2019, SBLC's for exploratory and operational commitments totaled $60.2 million.

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 less than or equal to 3.0:1.0, and ensure a cash balance of at least $200 million as of the last day of the most recent fiscal quarter. As at June 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 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 June 30, 2019, undiscounted and by calendar year, are presented below:

As at June 30, 2019	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	33,704	33,519	18,278	8,611	3,377	—	97,489
Total Financial Obligations	**$ 50,679**	**$ 67,469**	**$ 52,228**	**$ 42,561**	**$ 370,352**	**$ —**	**$ 583,289**
Transportation and Storage Commitments							
Ocensa P-135 ship-or-pay agreement	31,690	64,481	66,141	67,842	69,588	105,836	405,578
Puerto Bahia take-or-pay agreement (1)	9,774	25,861	26,488	—	—	—	62,123
ODL ship-or-pay agreement	23,676	30,404	—	—	—	—	54,080
Bicentenario take-or-pay storage agreements	3,917	7,834	7,834	7,834	7,834	6,051	41,304
Other transportation agreements	19,501	30,357	30,357	30,287	29,444	133,554	273,500
Exploration Commitments							
Minimum work commitments	53,358	127,393	43,386	4,500	4,500	4,500	237,637
Other Commitments							
Operating purchases and leases (2)	18,290	8,448	8,108	7,566	7,166	11,909	61,487
Community obligations	8,520	310	—	—	—	—	8,830
Total Commitments	**$ 168,726**	**$ 295,088**	**$ 182,314**	**$ 118,029**	**$ 118,532**	**$ 261,850**	**$1,144,539**

1. Excludes the lease component for ROU, 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. No material changes have occurred with respect to 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 July 31, 2019:

	Number
Common shares	97,955,618
Deferred share units ("**DSUs**") (1)	228,743
Restricted share units ("**RSUs**") (2)	1,822,978

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

During the second quarter of 2019, the Company repurchased for cancellation 151,500 Common Shares for $1.3 million under its NCIB. As at June 30, 2019, the Company has repurchased for cancellation a total of 2,684,605 Common Shares for $27.7 million under the NCIB, which commenced on July 18, 2018.

Dividends

On December 5, 2018, the Company adopted a dividend policy, which includes 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 $15.0 million during periods in which Brent oil prices sustain an average price of US$60/bbl or higher. The payment of any specific quarterly dividend is subject to approval of the Board in its discretion.

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

Declaration date	Record date	Payment date	Dividend (C$/ share)	Dividends paid ($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

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 (before impairment) and commitments with related parties, as at June 30, 2019 and December 31, 2018, and for the three and six months ended June 30, 2019 and 2018, respectively:

($M)		Accounts Receivable (1)	Accounts Payable	Commitments	Cash Advance (1)	Loans / Debentures Receivable (1)	Interest Receivable (1)
ODL	2019	—	5,520	54,080	—	—	—
	2018	9,116	1,481	82,073	—	—	—
Bicentenario	2019	35,638	—	41,304	87,278	—	—
	2018	20,177	—	43,200	87,278	—	—
IVI	2019	11,191	2,431	62,123	17,741	125,033	44,116
	2018	8,902	1,104	123,330	17,741	114,134	37,158
CGX (2)	2018	—	—	—	—	25,945	2,186

($M)		Three Months Ended March 31			Six Months Ended June 30		
		Sales	Purchases / Services	Interest Income	Sales	Purchases / Services	Interest Income
ODL	2019	—	13,001	—	—	25,683	—
	2018	350	9,584	—	1,359	21,546	—
Bicentenario	2019	—	1,818	—	—	3,675	—
	2018	—	24,700	—	—	52,798	—
IVI	2019	—	6,969	3,554	—	15,120	6,957
	2018	—	6,471	2,430	—	12,804	4,483
CGX (2)	2019	—	—	—	—	—	363
	2018	158	—	111	309	—	443
Interamerican (3)	2018	—	—	83	3	2	167

1. Amounts presented based on contractual payment obligations undiscounted, prior to impairments.
2. Balances shown reflect transactions before the Company acquired control of CGX through its participation in an equity rights offering on March 13, 2019. As a result of its participation, the Company's equity interest in CGX is 67.8%. Refer to Note 3 of the Interim Financial Statements.
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 risks, including but not limited to, operational, financial, competitive, political and environmental risks.

The Company is exposed to operational risks such as unsuccessful exploration and exploitation activities, inability to find new reserves that are commercially and economically feasible, uneconomic transportation methods, premature declines of reservoirs, changes to environmental regulations, and other customary operating hazards and risks. The Company attempts to mitigate these risks by employing highly skilled employees and utilizing available technology. Furthermore, the Company maintains 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 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 of 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 prospective 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 June 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:

	Average Net Production (in boe/d)				
Producing blocks in Colombia	**Q2 2019**	**Q1 2019**	**Q2 2018**	**YTD 2019**	**YTD 2018**
Light and medium oil	27,574	30,209	28,574	28,884	27,854
Heavy oil	28,670	28,037	23,867	28,355	24,465
Natural gas	2,454	2,651	4,504	2,552	4,688
Net production Colombia	**58,698**	**60,897**	**56,945**	**59,791**	**57,007**
Producing blocks in Peru					
Light and medium oil	8,416	1,996	7,195	5,224	8,171
Net production Peru	**8,416**	**1,996**	**7,195**	**5,224**	**8,171**
Total net production	**67,114**	**62,893**	**64,140**	**65,015**	**65,178**

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		