MANAGEMENT DISCUSSION & ANALYSIS

May 8, 2019
For the three months ended March 31, 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 months ended March 31, 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 page13.*

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 anticipated levels of production, estimated costs and timing of Frontera's planned work programs and reserves determination, the timing of payment of dividends 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. Ricks 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 that increase costs for the Company, 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 Operating Summary

		Q1 2019	Q4 2018	Q1 2018
Operational Results				
Oil production	(bbl/d)	65,323	68,661	68,983
Natural gas production	(boe/d)	2,651	3,263	4,875
Production [(1)]	(boe/d) [(2)]	67,974	71,924	73,858
Oil and gas sales and other revenue	($/boe)	58.08	60.06	61.34
Realized loss on risk management contracts	($/boe)	(0.30)	(5.55)	(8.98)
Royalties	($/boe)	(1.74)	(2.94)	(1.74)
Diluent costs	($/boe)	(1.71)	(2.22)	(1.88)
Net sales realized price [(3)]	($/boe)	54.33	49.35	48.74
Production costs [(4)]	($/boe)	(11.40)	(12.76)	(11.11)
Transportation costs [(5)]	($/boe)	(12.70)	(12.89)	(12.68)
Operating netback [(6)]	($/boe)	30.23	23.70	24.95
Financial Results				
Oil and gas sales and other revenue	($M)	313,459	277,944	289,534
Realized loss on risk management contracts	($M)	(1,593)	(25,667)	(42,393)
Royalties	($M)	(9,376)	(13,597)	(8,194)
Diluent costs	($M)	(9,217)	(10,291)	(8,865)
Net sales [(6)]	($M)	293,273	228,389	230,082
Net income (loss) [(7)]	($M)	46,187	(116,631)	(3,121)
Per share – basic and diluted [(8)]	($)	0.47	(1.17)	(0.03)
General and administrative	($M)	16,492	21,839	22,053
Operating EBITDA [(6)]	($M)	144,855	118,398	85,988
Cash provided (used) by operating activities	($M)	72,075	(3,494)	28,345
Capital expenditures [(9)]	($M)	69,219	156,400	78,841
Cash and cash equivalents – unrestricted	($M)	340,671	446,132	515,811
Restricted cash short and long-term	($M)	146,517	142,305	180,112
Total cash	($M)	487,188	588,437	695,923
Total debt and lease liabilities [(10)]	($M)	417,751	354,363	268,237

1. Represents working interest production before royalties and total volumes produced from service contracts. Refer to the “Further Disclosures” section on page 20.
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 13. 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 First Quarter of 2019

Financial and Operational Results

- Net income for the first quarter of 2019 was $46.2 million ($0.47/share) compared with a net loss of $3.1 million ($0.03/share) in the same period of 2018.
- Cash from operating activities was $72.1 million in the first quarter of 2019, compared to $28.3 million in the same prior year period, contributing to a total cash position of $487.2 million at March 31, 2019 (including restricted cash of $146.5 million).
- Operating EBITDA in the first quarter of 2019 was $144.9 million, compared to $86.0 million in the same period of 2018. The adoption of IFRS 16 increased Operating EBITDA by $5.7 million, or 5%, compared to the prior period as the standard was applied prospectively on January 1, 2019.
- Production averaged 67,974 boe/d during the first quarter of 2019, within the annual guidance of 65,000 to 70,000 boe/d, 5% lower than the fourth quarter of 2018 and 8% lower than the first quarter of 2018. Production in Colombia was 4% higher than both comparable periods offsetting declines in Peru following a force majeure event suspending production from Block 192.
- Oil and gas sales and other revenue was $313.5 million in the first quarter of 2019, an increase of 8% compared to the same period in 2018. Net sales for the first quarter of 2019 (including the impact of realized losses on risk management contracts, royalties and diluent costs) increased by 27% compared to the first quarter of 2018.
- Operating netback in the first quarter of 2019 was $30.23/boe, 21% higher than $24.95/boe in the first quarter of 2018 and 28% higher than $23.70/boe in the fourth quarter of 2018. The adoption of IFRS 16 increased Operating Netback by $0.77/boe, or 3%, compared to the prior period.
- Capital expenditures during the first quarter of 2019 were $69.2 million compared to $78.8 million in the same prior year period.

CGX Energy Inc. ("CGX") Update

- On January 31, 2019, the Company entered in to a farm-in joint venture agreement with CGX, which was subsequently approved by the Government of The Cooperative Republic of Guyana in May 2019, relating to two shallow water offshore Petroleum Prospecting Licenses in Guyana: the Corentyne and Demerara blocks. Under the terms of the farm-in joint venture agreement, the Company will acquire a 33.333% working interest in the two blocks in exchange for a $33.3 million transfer bonus.
- On March 13, 2019, the Company acquired 101,316,916 common shares of CGX for cash consideration of $19.0 million in connection with an equity rights offering (the "**Rights Offering**"). As a result of its participation in the rights offering, the Company now owns or exercises control over 67.8% of the issued and outstanding common shares of CGX. As consideration for providing a standby commitment in connection with the rights offering, the Company also received 5-year warrants to purchase up to 15,009,026 common shares at an exercise price equal to C$0.415/share. Assuming the exercise or conversion of the warrants and convertible bridge loan, the Company owns or exercises control over approximately 73.95% of the issued and outstanding common shares of CGX on a partially diluted basis.

Portfolio Enhancements

- On January 29, 2019, the Company signed a farm-in agreement with Parex Resources Inc. ("**Parex**"), subject to regulatory approval, whereby the Company will receive a 50% working interest in the VIM-1 Block in the Lower Magdalena Valley basin in Colombia in exchange for funding 100% of the first $10 million of the drilling, testing and completion costs of an exploration well, after which costs on the block will be split 50% with Parex.
- On March 12, 2019, a consortium formed by the Company and GeoPark Limited ("**GeoPark**") (Frontera 50%, GeoPark 50%) was preliminarily awarded the Perico and Espejo blocks that were offered by the Ecuadorian Government as part of the Intracampos Bid Round. On April 23, 2019, the Ecuadorian Ministry of Energy and Non-Renewable Natural Resources notified the Company that the award had been confirmed. Execution of the corresponding participation agreements is expected to occur before the end of May 2019.

Shareholder Value Initiatives

- On January 17, 2019, the Company paid a dividend of $24.5 million (C$0.33/share) to shareholders of record on January 3, 2019, with 23.8% of shareholders electing to participate in the Company's Dividend Reinvestment Plan ("**DRIP**"). On April 16, 2019, the Company paid a dividend of $12.1 million (C$0.165/share) to shareholders of record on April 2, 2019, with 0.2% of shareholders electing to participate in the DRIP.
- During the first quarter of 2019, the Company repurchased for cancellation 942,520 Common Shares for $8.6 million under its Normal Course Issuer Bid ("**NCIB**"). As at April 30, 2019, the Company had repurchased for cancellation a total of 2,662,105 Common Shares for $27.6 million with an additional 2,338,478 Common Shares available for repurchase under the NCIB.

Pacific Midstream Limited ("PML") Update

- On March 22, 2019, the Company acquired PML ownership interest in the Bicentenario pipeline for approximately $84.8 million. The net cash cost of the acquisition was approximately $34.0 million after the proceeds of the transaction were distributed by PML to its shareholders. As previously disclosed, this acquisition was triggered by the International Financial Corporation and related funds (the "**IFC**") as a result of the termination of the Company's take or pay contracts when the Bicentenario pipeline was non-operational for six consecutive months. With the completion of the transaction, the Company's aggregate indirect ownership interest in the Bicentenario pipeline increased to 43.0% from 26.4%.

2. GUIDANCE

There are no changes to the Company's guidance, which was released on December 6, 2018.

		2019	
		Guidance (1, 2)	Q1 Actual
Average production	(boe/d)	65,000 to 70,000	67,974
Average net production	(boe/d)	60,000 to 65,000	62,893
Production costs	($/boe)	12.50 to 13.50	11.40
Transportation costs	($/boe)	12.50 to 13.50	12.70
Operating EBITDA	($MM)	400 to 450	145
Capital expenditures	($MM)	325 to 375	69

1. The guidance assumes $65.00/bbl Brent, realized oil price differentials of $8.40/bbl and foreign exchange rate of 3,000 COP to 1 USD.
2. The guidance for operating EBITDA and capital expenditures are aggregate ranges for the year.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average daily field production, production before royalties and net production from the Company's producing blocks in Colombia and Peru.

	Average Production (in boe/d)					
	Production			Net Production		
Producing blocks in Colombia	**Q1 2019**	**Q4 2018**	**Q1 2018**	**Q1 2019**	**Q4 2018**	**Q1 2018**
Light and medium oil	32,394	29,843	29,370	30,209	28,022	27,125
Heavy oil	30,658	29,844	28,876	28,037	24,963	25,070
Natural gas	2,651	3,263	4,875	2,651	3,263	4,875
Total production Colombia	**65,703**	**62,950**	**63,121**	**60,897**	**56,248**	**57,070**
Producing blocks in Peru						
Light and medium oil	2,271	8,974	10,737	1,996	7,650	9,157
Total production Peru	**2,271**	**8,974**	**10,737**	**1,996**	**7,650**	**9,157**
Total production	**67,974**	**71,924**	**73,858**	**62,893**	**63,898**	**66,227**

Colombia

Production in Colombia for the first quarter of 2019 averaged 65,703 boe/d, an increase of 4% compared to both the fourth quarter and first quarter of 2018. The increase was the result of higher production at the Quifa Block following the commissioning of the water handling expansion project and the Guatiquia Block from the Candelilla-7 development well. The production increases from light, medium and heavy oil blocks were partially offset by lower production from the Company's natural gas assets in Colombia.

Peru

Production in Peru for the first quarter of 2019 averaged 2,271 boe/d, a decrease of 75% compared to the fourth quarter of 2018 and 79% compared to the first quarter of 2018. This decrease was due to the shutdown of Block 192 as a result of a force majeure event relating to the NorPeruano pipeline from November 27, 2018, until March 1, 2019. Production from Block 192 in Peru contributed approximately 1,720 boe/d in the first quarter of 2019, as production from the block gradually restarted during March 2019.

Production Reconciled to Sales Volumes

		Q1 2019	Q4 2018	Q1 2018
Production	**(boe/d)**	**67,974**	**71,924**	**73,858**
Royalties in-kind Colombia	(boe/d)	(4,806)	(6,702)	(6,051)
Royalties in-kind Peru [(1)]	(boe/d)	(275)	(1,324)	(1,580)
Net production	**(boe/d)**	**62,893**	**63,898**	**66,227**
Oil inventory draw (build)	(boe/d)	962	(5,797)	(7,282)
Settlement of overlift positions	(boe/d)	—	(8,792)	(3,161)
Sales volumes from E&E assets [(2)]	(boe/d)	(63)	(911)	(1,168)
Other inventory movements [(3)]	(boe/d)	(3,824)	1,900	(2,176)
Sales volumes	**(boe/d)**	**59,968**	**50,298**	**52,440**
Oil sales volumes	(boe/d)	57,363	47,058	47,646
Natural gas sales volumes	(boe/d)	2,605	3,240	4,794
Inventory balance				
Colombia	(bbl)	518,857	716,893	587,214
Peru	(bbl)	1,456,054	1,344,626	1,006,866
Inventory ending balance	**(bbl)**	**1,974,911**	**2,061,519**	**1,594,080**

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".
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 March 31, 2019, were higher than the comparable prior year periods primarily due to the settlement of overlift position using production of 8,792 bbl/d and 3,161 bbl/d in the fourth and first quarter of 2018, respectively. In Peru, the Company continued to experience higher inventory buildup relating to unsold production from Block 192 due to the Norperuano pipeline force majeure event.

Colombia Royalties - PAP

The Company makes high-price clause participation ("**PAP**") payments to Ecopetrol S.A. and the Agencia Nacional de Hidrocarburos ("**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 and escalates as oil prices increase above a minimum baseline WTI price. Increases in benchmark 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 1.7% (combined cash and in-kind) of its production in the first quarter of 2019 as PAP, which was lower than both 3.2% paid in the same period of 2018 and 4.0% paid in the previous quarter. The Company paid PAP in-kind volumes averaging 1,446 bbl/d during the first quarter of 2019, compared with 1,361 bbl/d in the same quarter of 2018, and 2,405 bbl/d in the fourth quarter 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 March 31, 2019, the Company has received in-kind payments for its services equivalent to 83% of the production from the block, with the balance being retained by Perupetro. Perupetro retained in-kind volumes averaging 275 bbl/d during the three months ended March 31, 2019, compared with 1,580 bbl/d in the same period of 2018 and 1,324 boe/d in the fourth quarter 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 8.

Realized and Reference Prices

		Q1 2019	Q4 2018	Q1 2018
Reference price				
Brent	($/bbl)	63.83	68.60	67.23
Average realized prices				
Realized oil price	($/bbl)	59.70	62.15	63.43
Realized natural gas price	($/boe)	19.05	25.90	23.25
Other revenue (1)	($/boe)	0.15	0.24	1.59
Net sales realized price				
Oil and gas sales and other revenue	($/boe)	58.08	60.06	61.34
Realized loss on risk management contracts	($/boe)	(0.30)	(5.55)	(8.98)
Royalties	($/boe)	(1.74)	(2.94)	(1.74)
Diluent costs	($/boe)	(1.71)	(2.22)	(1.88)
Net sales realized price	**($/boe)**	**54.33**	**49.35**	**48.74**

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).

Crude oil prices fell during the first quarter of 2019, reaching their lowest level in more than a year with the Brent benchmark price averaging 7%, or $4.77/bbl, lower than the fourth quarter of 2018 and 5%, or $3.40/bbl, lower than the first quarter of 2018. The reduction in global crude oil prices was mostly attributable to a weaker global economic outlook, lower manufacturing and industrial output and higher oil supply leading to higher than expected crude oil inventories. This was partially offset by the realization of narrower price differentials in the first quarter of 2019 as the global market remains short on heavy grade crude oil. For the three months ended March 31, 2019, the Company's net sales realized price was $54.33/boe, an increase of 10% compared to the previous quarter and 11% compared to the first quarter of 2018 mainly due to lower realized losses from risk management contracts compared to prior periods. Refer to the "Gain (Loss) on Risk Management Contracts" on page 11.

Operating Netback

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

	Q1 2019		Q4 2018		Q1 2018	
	$M	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**
Net sales realized price (1)	293,273	54.33	228,389	49.35	230,082	48.74
Production costs (2)	(69,758)	(11.40)	(84,441)	(12.76)	(73,879)	(11.11)
Transportation costs (3)	(71,906)	(12.70)	(75,748)	(12.89)	(75,578)	(12.68)
Operating Netback (4)	**151,609**	**30.23**	**68,200**	**23.70**	**80,625**	**24.95**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes (D&P) (5)		59,968		50,298		52,440
Production (6)		67,974		71,924		73,858
Net production (6)		62,893		63,898		66,227

1. Per boe is calculated using sales volumes from D&P assets. Refer to the "Realized and Reference Prices" above.
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 8 for fees that are not included in table.
4. Refer to the "Non-IFRS Measures" section on page 13 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 first quarter of 2019 was $30.23/boe, compared $23.70/boe in the fourth quarter of 2018 and $24.95/boe in the same quarter of 2018. The increase was primarily due to the higher net sales realized price in the current quarter. Although benchmark oil prices were lower than the comparable periods, the Company had significantly more hedges in the prior year resulting in higher realized losses from risk management contracts in 2018. While transportation costs per boe remained relatively constant, production costs per boe decreased relative to the prior quarter due to fewer well services in Colombia. In comparison to the first quarter of 2018, production costs per boe were higher as a result of lower average production in Peru during the first quarter of 2019 due to a force majeure event on the Norperuano pipeline.

Sales

	Three Months Ended March 31	
($M)	**2019**	**2018**
Oil and gas sales and other revenue	313,459	289,534
Realized loss on risk management contracts	(1,593)	(42,393)
Royalties	(9,376)	(8,194)
Diluent costs	(9,217)	(8,865)
Net sales	**293,273**	**230,082**
$/boe using sales volumes from D&P assets	54.33	48.74

Oil and gas and other revenue for the three months ended March 31, 2019, increased by $23.9 million compared to the same period in 2018, mainly due to a 14% increase in volumes sold. Net sales for the three months ended March 31, 2019, increased by $63.2 million compared to the same period in 2018. The following table describes the various factors that impacted net sales:

	Three Months Ended March 31
($M)	**2019-2018**
Net sales for the period ended March 31, 2018	230,082
Decrease due to 5% lower oil and gas price per barrel	(17,634)
Lower realized loss on risk management contracts	40,800
Increase in royalties	(1,182)
Increase due to higher volumes sold of 7,528 boe/d or 14%	41,559
Increase in diluent costs	(352)
Net sales for the period ended March 31, 2019	**293,273**

Royalties

	Three Months Ended March 31	
($M)	**2019**	**2018**
Cash royalties Colombia	9,156	7,943
Cash royalties Peru	220	251
Royalties	**9,376**	**8,194**
$/boe using sales volumes from D&P assets	1.74	1.74

Royalties include PAP payments, cash royalties and amounts paid to previous owners of certain blocks in Colombia. For the three months ended March 31, 2019, royalties increased by $1.2 million compared to the same period in 2018, due to higher production in the current quarter from Colombia. On a per boe basis, royalties of $1.74/boe remained consistent in both quarters. 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

($M)	Three Months Ended March 31 2019	2018
Transportation costs	71,906	75,578
Production costs	69,758	73,879
Diluent costs	9,217	8,865
Overlift (settlement)	20	(17,019)
Inventory valuation	(7,072)	(9,813)
Total oil and gas operating costs	**143,829**	**131,490**

Total oil and gas operating costs for the three months ended March 31, 2019, increased by 9%, or $12.3 million, compared to the same period in 2018. Total oil and gas operating costs changed mainly due to the following:

- Transportation costs decreased by 5% in the three months ended March 31, 2019, compared with the same period of 2018, mainly due to lower tariffs at Oleoducto Central S.A. ("**Ocensa**") and less expensive transportation alternatives used in 2019. Additionally, transportation costs were reduced by $2.4 million as certain storage facilities are now capitalized due to the adoption of IFRS 16.

- Production costs decreased by 6% in the three months ended March 31, 2019, compared to the same period of 2018, mainly as a result of lower costs from Peru due to a force majeure event on the Norperuano pipeline.

- Diluent costs for the three months ended March 31, 2019, was comparable with the same period of 2018.

- Overlift (settlement) decreased due to the settlement of an overlift balance during the first quarter of 2018 as production was delivered to settle the overlift liability and recognized a gross margin of $17.0 million. The Company had no overlift positions during the first quarter of 2019.

- Inventory valuation decreased by $2.7 million in the three months ended March 31, 2019, compared with the same period of 2018, due to the inventory buildup of 7,282 boe/d in the first quarter of 2018.

Other selected operating costs

($M)	Three Months Ended March 31 2019	2018
Fees paid on suspended pipeline capacity	—	35,904

Fees paid on suspended pipeline capacity were $Nil for the first quarter of 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. ("**CENIT**") in July 2018.

General and Administrative

($M)	Three Months Ended March 31 2019	2018
General and administrative	16,492	22,053

General and administrative expenses ("**G&A**") for the three months ended March 31, 2019, decreased by 25% compared to the same period in 2018. Lower G&A reflects a reduction in employee-related expenses as a result of the Company's continued efforts to reduce overhead costs and lower office lease costs of $1.4 million due to the adoption of IFRS 16.

Depletion, Depreciation and Amortization

	Three Months Ended March 31	
($M)	**2019**	**2018**
Depletion, depreciation and amortization	93,146	72,673

Depletion, depreciation and amortization expense (“**DD&A**”) increased by 28% for the three months ended March 31, 2019, compared to the same period 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.

Impairment

	Three Months Ended March 31	
	2019	**2018**
Impairment of investment in associates	—	11,216
Impairment of PEL power transmission line assets	—	9,125
Impairment	**—**	**20,341**

In the first quarter of 2018, the Company recognized an impairment charge of $9.1 million from the sale of the Company’s transmission line assets owned by PEL (the sale was closed in the second quarter of 2018) and an impairment of $11.2 million related to the Company’s investment in Interamerican Energy Corporation.

Non-Operating Costs

	Three Months Ended March 31	
($M)	**2019**	**2018**
Finance income	6,030	5,563
Finance expenses	(13,675)	(9,810)
Share of income from associates	23,498	35,759
Foreign exchange gain	602	19,005
Other income (loss), net	11,294	(604)

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. In the first quarter of 2019, net finance expense increased to $7.6 million from $4.2 million in the prior year quarter primarily due to interest on lease liabilities recognized on the adoption of IFRS 16.

Share of Income from Associates

The Company holds investments in associates that are accounted for using the equity method of accounting, which requires that the Company increase or decrease the carrying value of its investment by its proportionate share of the net earnings or loss of the underlying investees.

The share of income from associates for the three months ended March 31, 2019, decreased to $23.5 million from $35.8 million in the same period of 2018, mainly due to lower income from Bicentenario after the termination of the Company’s transportation contracts in July 2018.

Foreign Exchange Gain

Foreign exchange gains and losses primarily result from the movement of the COP against the USD as a significant portion of the Company’s working capital and expenditures are denominated in COP. During the first quarter of 2019, the COP appreciated against the USD by 2% in comparison with an appreciation of 7% in the comparable quarter. The foreign exchange gain in the first quarter of 2019 was $0.6 million compared with $19.0 million in the first quarter of 2018, primarily due to the impact of the lower appreciation of the COP on the translation of the Company’s net working capital balances.

Other Income (Loss), net

For the three months ended March 31, 2019, other income was $11.3 million compared with a loss of $0.6 million in the same prior year quarter primarily related to a gain of $10.9 million on remeasurement of the Company's previously held 48.2% equity interest in CGX to fair value immediately prior to the acquisition.

Gain (Loss) on Risk Management Contracts

	Three Months Ended March 31	
($M)	**2019**	**2018**
Realized loss on risk management contracts [1]	(1,593)	(42,393)
Unrealized (loss) gain on risk management contracts [2]	(6,187)	17,313
Total loss on risk management contracts	**(7,780)**	**(25,080)**

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

For the three months ended March 31, 2019, realized loss on risk management contracts was $40.8 million lower than the same prior year quarter primarily as a result of differences in the underlying hedging instruments that expired or settled during each period. During the first quarter of 2019, Brent oil put options expired (which limited the loss to the premiums paid) compared to the first quarter of 2018 when zero cost collars were settled at prices that were significantly higher than average ceiling prices.

In the first quarter of 2019, the Company recognized an unrealized loss of $6.2 million due to the crude oil benchmark forward prices increasing over the contract periods compared to an unrealized gain of $17.3 million in the first quarter of 2018 primarily related to the reversal of prior unrealized amounts on the settlement of zero cost collars expiring in 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 primarily put options in order 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.

				Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads $**	**Assets**	**Liabilities**
Put options	April 2019 to September 2019	Brent	4,130,960	55.00	2,009	—
Zero cost collars	October 2019 to December 2019	Brent	236,000	57.00-75.60	86	—
Total as at March 31, 2019					**2,095**	—
Put options	January 2019 to September 2019	Brent	2,220,000	55.00	9,380	—
Total as at December 31, 2018					**9,380**	**—**

During April 2019, the Company continued with its hedging program, adding the following positions subsequent to March 31, 2019 as follows:

				Strike Prices
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads $**
Put options	September 2019 to December 2019	Brent	1,803,000	60.00
Zero cost collars	August 2019 to March 2020	Brent	2,148,000	57.50 - 75.70
Total			**3,951,000**	

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations primarily from the movement in the COP:USD exchange rate as significant operating expenditures are incurred in COP. The Company monitors and manages its exposure to such foreign currency risks through the use of currency derivative contracts. As at March 31, 2019, the Company has entered into foreign currency derivative contracts (zero cost collars) for $0.2 million, expiring between April 2019 and September 2019.

						Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**		**Notional Amount / Volume USD**	**Put / Call; Par forward COP**	**Assets**	**Liabilities**
Zero cost collars	April 2019 to September 2019	COP / USD	$	195,000	3,000 / 3,370	—	(483)
Total as at March 31, 2019						**—**	**(483)**
Zero cost collars	January to June 2019	COP / USD	$	172,500	3,000 / 3,440	—	(3,299)
Forward	January to March 2019	COP / USD	$	22,500	3,109	—	(1,019)
Total as at December 31, 2018						**—**	**(4,318)**

	Assets	**Liabilities**
Total risk management contracts as at March 31, 2019	2,095	(483)
Total risk management contracts as at December 31, 2018	9,380	(4,318)

Income Tax Expense

	Three Months Ended March 31	
($M)	**2019**	**2018**
Current income tax expense	(3,533)	(10,329)
Deferred income tax expense	(18,153)	(417)
Total income tax expense	**(21,686)**	**(10,746)**

The current income tax expense for the first quarter of 2019 was $3.5 million, which includes minimum income taxes (presumptive tax) of $2.5 million, a tax of $1.3 million from dividends of investments in associates and current taxes in countries other than Colombia of $0.3 million. In addition, during the quarter ended March 31, 2019, the Company recognized an income tax expense of $18.2 million related to the utilization of the deferred tax asset.

For more information, refer to Note 7 of the Interim Financial Statements.

Net Income (Loss)

	Three Months Ended March 31	
($M)	**2019**	**2018**
Net income (loss) attributable to equity holders of the Company	46,187	(3,121)
Per share – basic and diluted	0.47	(0.03)

For the three months ended March 31, 2019, the Company reported a net income of $46.2 million compared to a net loss of $3.1 million in the first quarter of 2018. This was primarily due to lower impairment charges of $20.3 million in the current quarter and no fees paid on suspended capacity in the current quarter as compared to $35.9 million during the first quarter of 2018.

Capital Expenditures

($M)	Three Months Ended March 31 2019	2018
Maintenance and development drilling	52,867	43,783
Facilities and infrastructure	7,637	7,655
Exploration activities [1]	8,260	24,836
Administrative assets and other projects	455	2,567
Total capital expenditures	**69,219**	**78,841**

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

Capital expenditures for the three months ended March 31, 2019 was $69.2 million, 12% lower than the same period of 2018. A total of 29 development wells and two exploration wells were drilled during the first quarter of 2019, compared to 33 development wells and three exploration wells in the first quarter of 2018. The Company continues to invest in exploration and development drilling with eight rigs in operation during the first quarter of 2019, including four in the Quifa, one in the Sabanero heavy oil blocks, and three in the light oil-focused blocks (Guatiquia, Cravoviejo and Cubiro blocks).

Selected Quarterly Information

		2019	2018				2017		
		Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Operational and financial results									
Oil production	(bbl/d)	65,323	68,661	62,271	67,522	68,983	64,559	71,984	72,611
Natural gas production	(boe/d)	2,651	3,263	4,122	4,504	4,875	5,315	5,427	5,922
Production	(boe/d)	67,974	71,924	66,393	72,026	73,858	69,874	77,411	78,533
Oil and gas natural gas sales volumes	(boe/d)	59,968	50,298	61,071	67,822	52,440	65,481	63,162	64,908
Brent price	($/bbl)	63.83	68.60	75.84	74.97	67.23	61.46	52.17	50.79
Oil and gas sales and other revenue	($/boe)	58.08	60.06	68.02	67.82	61.34	56.19	47.55	45.71
Realized loss on risk management contracts	($/boe)	(0.30)	(5.55)	(10.02)	(11.12)	(8.98)	(2.93)	0.31	0.57
Royalties	($/boe)	(1.74)	(2.94)	(2.83)	(2.19)	(1.74)	(1.35)	(0.81)	(0.97)
Diluent costs	($/boe)	(1.71)	(2.22)	(1.89)	(1.74)	(1.88)	(1.00)	(1.21)	(1.22)
Net sales realized price	($/boe)	54.33	49.35	53.28	52.77	48.74	50.91	45.84	44.09
Production costs	($/boe)	(11.40)	(12.76)	(13.84)	(12.44)	(11.11)	(11.98)	(9.87)	(9.04)
Transportation costs	($/boe)	(12.70)	(12.89)	(13.77)	(11.81)	(12.68)	(14.28)	(11.77)	(14.19)
Operating netback	($/boe)	30.23	23.70	25.67	28.52	24.95	24.65	24.20	20.86
Revenue [1]	($M)	377,527	265,109	366,511	405,198	283,667	344,862	300,574	290,397
Net income (loss)	($M)	46,187	(116,631)	45,105	(184,436)	(3,121)	(32,544)	(141,115)	(51,542)
Per share – basic and diluted	($)	0.47	(1.17)	0.45	(1.84)	(0.03)	(0.33)	(1.41)	(0.52)
General and administrative	($M)	16,492	21,839	22,962	26,168	22,053	24,450	26,569	26,098
Operating EBITDA	($M)	144,855	118,398	93,455	124,667	85,988	104,316	110,243	86,857
Capital expenditures	($M)	69,219	156,400	124,029	86,813	78,841	111,213	48,563	37,826

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 as 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 changes in unrealized gains and losses from risk management activities that fluctuate with changes in forward market prices, DD&A and net impairment charges of oil, gas and other assets.

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

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:

	Three Months Ended March 31	
($M)	**2019**	**2018**
Net income (loss)	46,187	(3,121)
Fees paid on suspended pipeline capacity	—	35,904
Share-based compensation	572	1,054
Depletion, depreciation and amortization	93,146	72,673
Impairment	—	20,341
Restructuring, severance and other costs	1,440	2,838
Share of income from associates	(23,498)	(35,759)
Foreign exchange gain	(602)	(19,005)
Finance income	(6,030)	(5,563)
Finance expenses	13,675	9,810
Unrealized loss (gain) on risk management contracts	6,187	(17,313)
Other (income) loss, net	(11,294)	604
Income tax expense	21,686	10,746
Non-controlling interests	3,386	12,779
Operating EBITDA	**144,855**	**85,988**

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 7.

Operating Netback

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

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

Net sales realized price per boe is calculated using net sales (which includes 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 March 31	
($M)	**2019**	**2018**
Net sales	293,273	230,082
Denominator (boe)		
Sales volumes (D&P)	5,397,120	4,719,600
$/boe net sales realized price	54.33	48.74

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 March 31	
($M)	**2019**	**2018**
Production costs	(69,758)	(73,879)
Denominator (boe)		
Production	6,117,648	6,647,281
$/boe production costs	(11.40)	(11.11)

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 March 31	
($M)	**2019**	**2018**
Transportation costs	(71,906)	(75,578)
Denominator (boe)		
Net production	5,660,381	5,960,421
$/boe transportation costs	(12.70)	(12.68)

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 March 31, 2019, the Company had total cash balances of $487.2 million (including restricted cash of $146.5 million), a decrease of $101.2 million as compared to the prior year-end. This decrease was primarily due to the reduction of payables related to capital expenditures of $44.7 million in the quarter. The Company also paid $37.7 million of dividends to non-controlling interests, including $34.0 million relating to the acquisition of PML’s interest in the Bicentenario pipeline. Additionally, the Company paid a total of $33.1 million in dividends and share repurchases from equity holders.

Total cash balances include short and long-term restricted cash of $146.5 million, which are 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 March 31, 2019, the Company had a working capital surplus of $160.1 million, a decrease of $55.6 million as compared to the prior year-end primarily due to the capital investment at its production and exploration properties. 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 in June 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 March 31, 2019, the outstanding letters of credit issued and maintained under the Unsecured LC Facility for exploration and operational commitments totaled $35.5 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.

Covenants

The Unsecured Notes are senior, unsecured and rank equal in right of payment with all existing and future senior unsecured debt and are guaranteed by the Company's principal subsidiaries. Under the terms of both the Unsecured Notes and the Unsecured LC Facility, the Company may, among other things, incur indebtedness provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.0:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.5:1.0. In the event that 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 determined on a cumulative basis, subject to certain financial ratio tests and other conditions being met. As at March 31, 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 Contingencies

The Company's commitments and contractual obligations as at March 31, 2019, undiscounted and by calendar year, are presented below:

As at March 31, 2019	2019	2020	2021	2022	2023	2024 and beyond	Total
Financial Obligations							
Long-term debt, including interest payments	33,950	33,950	33,950	33,950	366,975	—	502,775
Lease liabilities	33,952	33,605	24,686	8,677	5,693	—	106,613
Transportation and Storage Commitments							
Ocensa P-135 ship-or-pay agreement	47,363	64,481	66,141	67,842	69,588	107,001	422,416
Puerto Bahia take-or-pay agreement (1)	18,758	26,365	26,471	—	—	—	71,594
Oleoducto de los Llanos Orientales S.A. ("**ODL**") ship-or-pay agreement	37,648	30,890	1,155	—	—	—	69,693
Bicentenario take-or-pay storage agreements	5,933	7,910	7,910	7,910	7,910	6,105	43,678
Other transportation agreements	77,439	31,696	31,146	31,074	30,232	134,526	336,113
Exploration Commitments							
Minimum work commitments	65,569	119,253	26,886	—	—	—	211,708
Other Commitments							
Operating purchases and leases (2)	24,891	8,266	8,033	7,639	7,235	12,021	68,085
Community obligations	7,708	310	—	—	—	—	8,018
Total	**$ 353,211**	**$ 356,726**	**$ 226,378**	**$ 157,092**	**$ 487,633**	**$ 259,653**	**$1,840,693**

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.

Transporte Incorporado S.A.S. - Assignment Agreement

On November 28, 2018, Transporte Incorporado S.A.S ("**Transporte Incorporado**") informed the Company of its intention to exercise the unilateral right to terminate the assignment agreement with the Company. Effective April 1, 2019, as a result of the exercise, Transporte Incorporado's transportation capacity rights related to the Oleoducto Central S.A. pipeline was transferred back to the Company. The Company paid Transporte Incorporado $48.5 million (included in other transportation commitments), after netting receivables owing of $20.1 million.

With the termination of the assignment agreement, the Company is no longer required to pay the set monthly premium from April 1, 2019 through March 31, 2024, to Transporte Incorporado. The effect of this termination has reduced other transportation commitments in the aggregate amount of $90.0 million. The Company will record an intangible asset of $68.6 million for the transportation rights at the effective date.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at May 8, 2019:

	Number
Common shares	97,955,374
Deferred share units ("**DSUs**") (1)	204,040
Restricted share units ("**RSUs**") (2)	1,885,954

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 first quarter of 2019, the Company repurchased for cancellation 942,520 Common Shares for $8.6 million under its NCIB. As at April 30, 2019, the Company has repurchased for cancellation a total of 2,662,105 Common Shares for $27.6 million with an additional 2,338,478 Common Shares available for repurchase under the NCIB.

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. The payment of any specific quarterly dividend will be subject to approval of the Board in its discretion.

The Company´s dividends paid or declared during the first quarter of 2019, are presented below:

Declaration Date	Record Date	Payment Date	Dividend (C$/share)	Dividend ($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

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 March 31, 2019, and December 31, 2018 and for the three months ended March 31, 2019 and 2018:

($M)		Accounts Receivable [1]	Accounts Payable	Commitments	Cash Advance [1]	Loans / Debentures Receivable [1]	Interest Receivable [1]
ODL	2019	—	1,489	69,693	—	—	—
	2018	9,116	1,481	82,073	—	—	—
Bicentenario	2019	35,971	—	43,678	87,278	—	—
	2018	20,177	—	43,200	87,278	—	—
Infrastructure Ventures Inc. ("**IVI**"), formerly Pacific Infrastructure Ventures Inc.	2019	10,002	1,158	71,594	17,741	114,134	40,562
	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 Sales	Purchases / Services	Interest Income [1]
ODL	2019	—	12,682	—
	2018	1,009	11,962	—
Bicentenario	2019	—	1,857	—
	2018	—	28,098	—
IVI	2019	—	9,380	3,403
	2018	—	6,333	2,053
CGX [2]	2019	—	—	363
	2018	151	—	332

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, refer to Note 3 of the Interim Financial Statements.

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 risk 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 material changes in the Company's ICFR during the quarter ended March 31, 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 44% to 84% of production on the Block. This percentage is determined by the “R” Factor, which is related to income and expenses in accordance with the service contract. The Company reports the share of production retained by the government under the contract as royalties paid in-kind in this MD&A.

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