MANAGEMENT DISCUSSION & ANALYSIS

August 2, 2018
For the three and six months ended June 30, 2018

*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 Colombia and Peru, 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 are listed and publicly traded on the Toronto Stock Exchange 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

*Certain statements in this Management, Discussion and Analysis ("**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, 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. Factors that could cause actual results to differ materially from those anticipated in these forward-looking statements are described in the Company's Annual Information Form ("**AIF**") for the year ended December 31, 2017, dated March 27, 2018.*

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.

*This 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 unaudited Interim Condensed Consolidated Financial Statements and related notes for the three and six months ended June 30, 2018 and 2017 ("**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 13.*

*In order to provide shareholders with full disclosure relating to potential future capital expenditures, the Company has provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts may differ, and these differences may be material. This information, among others, 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 best 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.*

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

Operating and Financial Summary

					Six months ended June 30	
		Q2 2018	Q1 2018	Q2 2017	2018	2017
Operational Results						
Net production [1]	(boe/d) [2]	64,140	66,227	72,370	65,178	72,446
Oil production	(bbl/d)	59,636	61,352	66,448	60,489	66,242
Natural gas production	(Mcf/d)	25,673	27,788	33,755	26,722	35,363
Combined realized price (including realized (loss) gain on risk management contracts)	($/boe)	56.70	52.36	46.28	54.82	46.11
Realized oil and natural gas and other revenue price	($/boe)	67.82	61.34	45.71	65.01	46.55
Realized (loss) gain on risk management contracts	($/boe)	(11.12)	(8.98)	0.57	(10.19)	(0.44)
Operating cost	($/boe)	(29.94)	(27.94)	(25.97)	(28.93)	(25.65)
Production cost	($/boe)	(14.13)	(12.47)	(9.93)	(13.29)	(9.68)
High-price participation payments and cash royalties	($/boe)	(2.16)	(1.30)	(0.75)	(1.73)	(0.82)
Transportation cost	($/boe)	(11.81)	(12.68)	(14.19)	(12.25)	(14.08)
Diluent cost	($/boe)	(1.84)	(1.49)	(1.10)	(1.66)	(1.07)
Operating Netback [3]	($/boe)	26.76	24.42	20.31	25.89	20.46
Adjusted Netback [3]	($/boe)	23.13	21.35	19.13	22.55	18.83
Adjusted FFO Netback [3]	($/boe)	17.53	16.64	11.76	17.39	12.59
Capital expenditures [4]	($M)	86,813	78,841	37,826	165,654	76,625
Financial Results						
Total sales	($M)	418,726	291,861	296,108	710,587	621,532
Oil and natural gas sales and other revenue	($M)	418,560	289,534	270,033	708,094	570,186
Sales of oil and natural gas for trading	($M)	166	2,327	26,075	2,493	51,346
Total sales after realized (loss) gain on risk management contracts [3]	($M)	350,113	249,468	299,452	599,581	616,090
Realized (loss) gain on risk management contracts	($M)	(68,613)	(42,393)	3,344	(111,006)	(5,442)
Net loss [5]	($M)	(184,436)	(3,121)	(51,542)	(187,557)	(43,044)
Per share – basic and diluted [6]	$	(1.84)	(0.03)	(0.52)	(1.88)	(0.43)
General and administrative	($M)	26,168	22,053	26,098	48,221	53,804
Operating EBITDA [3]	($M)	124,667	85,988	86,857	210,655	179,300
Adjusted EBITDA [3]	($M)	122,379	86,654	87,389	209,033	202,447
Net cash provided by operating activities	($M)	108,400	30,265	12,055	138,665	78,981
Adjusted FFO [3]	($M)	121,325	34,260	46,151	155,585	124,911
Per share – basic and diluted [6]	$	1.21	0.34	0.46	1.56	1.25
Total assets	($M)	2,556,781	2,664,920	2,621,871	2,556,781	2,621,871
Total cash	($M)	730,088	695,923	541,150	730,088	541,150
Cash and cash equivalents – unrestricted	($M)	550,840	515,811	439,479	550,840	439,479
Restricted cash – short and long-term	($M)	179,248	180,112	101,671	179,248	101,671
Total equity [7]	($M)	1,162,591	1,306,964	1,448,635	1,162,591	1,448,635
Debt and obligations under finance lease	($M)	352,806	268,237	271,181	352,806	271,181

1. *Net production represents the Company's working interest volumes, net of royalties and internal consumption.*
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. *Refer to the "Non-IFRS Measures" section on page 13.*
4. *Capital expenditures includes sales from Exploration and Evaluation ("**E&E**") assets.*
5. *Net loss attributable to equity holders of the Company.*
6. *The basic and diluted weighted average number of Common Shares are stated on an adjusted post split-split basis.*
7. *Equity attributable to equity holders of the Company.*

Performance Highlights for the Second Quarter of 2018

Operational and Financial Results

- Total sales for the second quarter of 2018 were $418.7 million, a 41% increase compared to $296.1 million in the same prior year period and a 43% increase compared to the first quarter of 2018, as the Company sold more volumes at higher prices.
- Net production averaged 64,140 boe/d during the second quarter of 2018, a decrease of 11% and 3% from the same period in 2017 and the first quarter of 2018, respectively. Average production remains within the range of annual guidance for 2018.
- Total operating costs averaged $29.94/boe in the second quarter of 2018, a 15% increase from the $25.97/boe reported for the same quarter of 2017, mainly due to lower production and the increase in oil prices, which resulted in higher costs for high-price participation payments ("**PAP**") and cash royalties. In comparison to the previous quarter, operating costs increased by 7% per boe.
- Operating netback for the quarter was $26.76/boe, 32% higher than the $20.31/boe reported in the second quarter of 2017 and 10% higher than the previous quarter's operating netback of $24.42/boe.
- Net loss for the quarter was $184.4 million ($1.84/share), higher than the net loss of $51.5 million ($0.52/share) in the same quarter of 2017. Included in this quarter's results was an impairment of $107.7 million relating to the investment in Oleoducto Bicentenario de Colombia S.A.S ("**Bicentenario**"), a non-cash loss of $50.8 million resulting from currency translation adjustments on the deconsolidation of Petroelectrica de los Llanos Ltd ("**PEL**") following its sale and a loss of $25.6 million on the extinguishment of long-term debt.
- Operating EBITDA was $124.7 million ($1.25/share) for the second quarter of 2018, an increase of 44% when compared to $86.9 million ($0.87 share) in the same period of 2017. In comparison to the previous quarter, operating EBITDA increased by 45% from $86.0 million.
- The Company generated $108.4 million of cash from operations in the quarter compared to $12.1 million in the same prior year period, contributing to an ending total cash position of $730.1 million at June 30, 2018.
- Adjusted funds flow from operations ("**Adjusted FFO**") was $121.3 million ($1.21/share) for the second quarter of 2018, higher than both $46.2 million ($0.46/share) in the prior year period and $34.3 million ($0.34/share) in the first quarter of 2018. Adjusted FFO netback was $17.53/boe for the second quarter of 2018, 49% higher than $11.76/boe reported in the same period of 2017, and 5% higher than $16.64/boe in the previous quarter.
- The Company continued to execute its strategy to position itself for growth in 2018 and beyond by investing in capital expenditures totalling $86.8 million during the second quarter of 2018, an increase of 130% from the same prior year period. A total of 24 development wells were drilled during the quarter.

Debt Refinancing and Extension of Credit Facility

- On June 25, 2018, the Company completed an offering of $350.0 million senior unsecured notes at a coupon rate of 9.7%, maturing in 2023 (the "**Unsecured Notes**"). The net proceeds from the Unsecured Notes were partially used to repurchase, at a premium, the Company's $250.0 million, 10.0% senior secured notes maturing in 2021 (the "**Secured Notes**"). The refinancing transaction successfully extended the maturity and reduced the Company's average cost of debt while securing an improved and more flexible set of covenants. As a result of the refinancing, the Company recognized a $25.6 million loss.
- On May 17, 2018, the Company replaced its amended and restated secured letter of credit facility (the "**Secured LC Facility**") with a new $100.0 million unsecured letter of credit facility (the "**New LC Facility**") with a maturity date of May 17, 2020.

Reduction in Transportation Commitments

- On July 12, 2018, the Company and Oleoducto Central S.A. ("**Ocensa**") reached a successful settlement agreement in an arbitration relating to transportation contracts on the P-135 Project (the "**P-135 Settlement Agreement**"). The P-135 Settlement Agreement is expected to reduce the Company's future transportation commitments by approximately $178.3 million over the term of the contract as average tariff rates were reduced by 35% per barrel.
- On July 13, 2018, the Company announced that it had exercised its rights to terminate its existing contracts with Bicentenario and Cenit Transporte y Logistica de Hidrocarburos S.A.S ("**CENIT**") to transport oil through the Bicentenario ("**BIC**") and Caño Limón ("**CLC**") pipelines, respectively. As a consequence of these terminations, the Company is no longer contractually committed to payments of ship-or-pay fees between July 12, 2018 and October 2028 through the CLC pipeline, and between July 12, 2018 and June 2024 through the BIC pipeline. As at June 30, 2018, these now terminated contracts represented $1.36 billion in future commitments. On July 16, 2018 and July 17, 2018, the Company received notices from Bicentenario and CENIT, respectively, disputing the grounds for the termination which the Company vigorously disputes.

Share Capital Transactions

- On June 26, 2018, the Company completed a two-for-one share split with Common Shares trading on a post-spit basis commencing on June 27, 2018.
- On July 13, 2018, the Company received approval from the Toronto Stock Exchange (the "**TSX**") to purchase up to 3,543,270 Common Shares, under a normal course issuer bid (the "**NCIB**"), over a twelve-month period commencing on July 18, 2018.

2. GUIDANCE

The Company has increased its annual Operating EBITDA guidance by 6% at the midpoint to $400 to $450 million from $375 to $425 million as a result of increasing the Brent oil price assumption to $70/bbl from $63/bbl. As a result of the recent arbitration settlement on the P-135 Project pipeline tariffs combined with year-to-date results, the Company is also narrowing the estimated range of transportation costs to $12.50/bbl - $13.50/bbl from $12.50/bbl - $14.50/bbl. Guidance for net production, production cost, general and administrative expenses and capital expenditures remain unchanged.

		2018 Guidance [1]		
		Original	**Revised**	**2018 YTD**
Average annual net production	(boe/d)	65,000 to 70,000	65,000 to 70,000	65,178
Production cost	($/boe)	12.00 to 14.00	12.00 to 14.00	13.29
Transportation cost	($/boe)	12.50 to 14.50	12.50 to 13.50	12.25
Operating EBITDA	($MM)	375 to 425	400 to 450	211
General and administrative expenses	($MM)	100 to 110	100 to 110	48
Capital expenditures	($MM)	450 to 500	450 to 500	166

1. *The guidance Operating EBITDA, general and administrative expenses, and capital expenditures are aggregate ranges for the year.*

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average daily production by total field, gross share and net production from all of the Company's producing fields in Colombia and Peru.

	Average Production (in boe/d)										
	Total field production			**Gross production before royalties [1]**			**Net production**				
Producing fields in Colombia	**Q2 2018**	**Q1 2018**	**Q2 2017**	**Q2 2018**	**Q1 2018**	**Q2 2017**	**Q2 2018**	**Q1 2018**	**Q2 2017**	**YTD 2018**	**YTD 2017**
Light and medium oil [2]	32,591	31,143	38,797	30,815	29,370	37,169	28,574	27,125	34,174	27,854	34,175
Heavy oil [3]	46,431	47,847	49,170	28,294	28,876	29,894	23,867	25,070	27,361	24,465	27,680
Natural gas [4]	5,148	5,566	6,753	4,504	4,875	5,922	4,504	4,875	5,922	4,688	6,204
Total production in Colombia	**84,170**	**84,556**	**94,720**	**63,613**	**63,121**	**72,985**	**56,945**	**57,070**	**67,457**	**57,007**	**68,059**
Producing fields in Peru											
Light and medium oil [5]	10,522	13,191	8,385	7,195	9,157	4,913	7,195	9,157	4,913	8,171	4,387
Total production in Peru	**10,522**	**13,191**	**8,385**	**7,195**	**9,157**	**4,913**	**7,195**	**9,157**	**4,913**	**8,171**	**4,387**
Total production in Colombia and Peru	**94,692**	**97,747**	**103,105**	**70,808**	**72,278**	**77,898**	**64,140**	**66,227**	**72,370**	**65,178**	**72,446**

1. *Gross working interest production before royalties, internal consumption and if applicable, PAP payments.*
2. *Includes Guatiquia, Cubiro, Cravoviejo, Casimena, Corcel, Casanare Este, CPI Neiva, Arrendajo, Cachicamo and other producing blocks. Casanare Este block is held for sale to Gold Oil PLC Sucursal Colombia, subject to the Agencia Nacional de Hidrocarburos (the "**ANH**") approval.*
3. *Includes Quifa, Cajua, CPE-6 and Sabanero blocks.*
4. *Includes La Creciente and Guama blocks.*
5. *Includes Block Z1 and Block 192 (2017 figures also includes production from Block 131 until its disposal on May 12, 2017).*

Net production during the second quarter of 2018 averaged 64,140 boe/d, 11% or 8,230 boe/d lower than the same period of 2017. For the six months ended June 30, 2018, average net production decreased by 10% to 65,178 boe/d from 72,446 boe/d in the same period of 2017. Net production decreases in both periods were primarily driven by natural declines in some of the Company's blocks located in Colombia and a higher burden from PAP paid using in-kind volumes. The Company also incurred unplanned operational events that temporarily interrupted production in the western Llanos Basin fields thereby deferring production volumes to future periods. During the latter half of the second quarter, the Company embarked on an intensive well service campaign in the affected wells and has now successfully re-activated nearly all the deferred production.

In addition, the Company experienced a temporary interruption at the Cubiro block when production was suspended during a community blockade that commenced in the first quarter of 2018. The community dispute was resolved at the end of the prior quarter and consequently had a positive impact on the second quarter production from the Cubiro Block due to re-pressurization of the reservoir during the period the Cubiro fields were shut-in. These factors were partially offset by an increase in production from the Quifa SW Block and Peru as a result of more stable operations in Block 192 compared to the significant downtime experienced during the same period in 2017.

In comparison to the first quarter of 2018, net production was 3% or 2,087 boe/d lower during the second quarter. This quarter-over-quarter decrease was primarily the result of a failure in the NorPeruano pipeline in Peru, which negatively impacted production beginning in early June. Production in Colombia was relatively unchanged compared to the previous quarter with increasing production in the light and medium fields offsetting declines in heavy oil.

PAP Payments

The Company makes PAP payments to Ecopetrol S.A. and the ANH on production at the Quifa, Cubiro, Corcel, Guatiquia and Cravoviejo 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 increase in benchmark oil prices has triggered higher PAP obligations payable both in-kind (therefore reducing the Company's net production) and in cash (therefore increasing operating costs).

The Company paid approximately 4.4% (combined cash and in-kind) of its total production in the quarter as PAP, which was higher than the 1.2% in the same period of 2017 and the 3.2% in the previous quarter of 2018. For the first half of 2018, the Company paid 3.8% from total production as compared with 1.3% in the first half of 2017. The Company paid in-kind volumes averaging 2,050 boe/d and 1,707 boe/d during the second quarter and first half of 2018, respectively, compared with no PAP in-kind volumes in both of the same prior year periods. In the first quarter of 2018, the Company paid 1,361 boe/d as PAP in-kind volumes.

Net production reconciled to sales volumes

					Six months ended June 30	
		Q2 2018	**Q1 2018**	**Q2 2017**	**2018**	**2017**
Net production	**(boe/d)**	**64,140**	**66,227**	**72,370**	**65,178**	**72,446**
Oil inventory draw (build)	(boe/d)	1,521	(7,282)	(2,476)	(2,856)	(1,530)
Overlift (settlement)	(boe/d)	3,493	(3,161)	(1,483)	184	3
E&E assets volumes sold (1)	(boe/d)	(979)	(1,168)	(1,502)	(1,073)	(1,479)
Other inventory movements (2)	(boe/d)	(353)	(2,176)	(2,001)	(1,259)	(1,775)
Sales volumes	**(boe/d)**	**67,822**	**52,440**	**64,908**	**60,174**	**67,665**
Oil sales	(boe/d)	63,283	47,646	59,191	55,508	61,746
Natural gas sales	(Mcf/d)	25,872	27,326	32,587	26,595	33,735

1. Volumes from E&E assets are excluded from total sales volumes because E&E revenues and costs are capitalized under IFRS.
2. Mainly corresponds to quality volumetric compensation, oil used for internal consumption and oil for trading.

During the second quarter of 2018, sales volumes of 67,822 boe/d were 29% higher than the 52,440 boe/d from the previous quarter. This was primarily due to two additional cargoes sold during the quarter of oil inventory that had built up from prior periods, including one cargo planned for delivery during the first quarter but not shipped until April 2018. As a result, the sale of this cargo totalling $31.1 million was recognized in the second quarter (refer to the MD&A for the first quarter of 2018). In addition, the Company sold more barrels than produced resulting in an overlift (see below) liability position of 313 Mbbl at the end of the quarter.

For the six months ended June 30, 2018, the Company experienced a buildup of inventory mainly relating to unsold production from Block 192 in Peru.

Overlift (settlement)

Overlift or 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 impact during the quarter. When the overlift is settled, this expense is reversed in order to recognize the gross margin earned on the related sale.

Netbacks

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

	Q2 2018		Q1 2018		Q2 2017	
	($/boe)	$M	($/boe)	$M	($/boe)	$M
Combined realized price (including realized (loss) gain on risk management contracts) [1]	**56.70**	**349,947**	**52.36**	**247,141**	**46.28**	**273,377**
Production cost	(14.13)	(82,450)	(12.47)	(74,322)	(9.93)	(65,390)
PAP and cash royalties	(2.16)	(12,598)	(1.30)	(7,751)	(0.75)	(4,922)
Transportation cost	(11.81)	(68,935)	(12.68)	(75,578)	(14.19)	(93,435)
Diluent cost	(1.84)	(10,741)	(1.49)	(8,865)	(1.10)	(7,225)
Total operating cost [2]	**(29.94)**	**(174,724)**	**(27.94)**	**(166,516)**	**(25.97)**	**(170,972)**
Operating Netback	**26.76**	**175,223**	**24.42**	**80,625**	**20.31**	**102,405**
Fees paid on suspended pipeline capacity [2]	(7.00)	(40,835)	(6.02)	(35,904)	(3.38)	(22,237)
Share of income from associates – pipelines [3]	3.37	19,671	2.95	17,607	2.20	14,505
Adjusted Netback	**23.13**	**154,059**	**21.35**	**62,328**	**19.13**	**94,673**
General and administrative [4]	(4.48)	(26,168)	(3.70)	(22,053)	(3.96)	(26,098)
Cash finance costs [5]	(1.09)	(6,374)	(1.05)	(6,250)	(0.95)	(6,250)
Other cash costs [6]	(0.03)	(192)	0.04	235	(2.46)	(16,174)
Adjusted FFO Netback	**17.53**	**121,325**	**16.64**	**34,260**	**11.76**	**46,151**
Net production volume (boe/d) [7]	64,140		66,227		72,370	
Sales volume (D&P) (boe/d) [8]	67,822		52,440		64,908	

Refer to the "Non-IFRS Measures" section on page 13 for definitions on how the Company calculates and uses operating netback, adjusted netback, and adjusted FFO netback. For reconciliations to IFRS figures, refer to:

1. *Per boe price calculated over sales volume D&P, in the "Realized and Reference Price" section on page 7. All other components of the netback are calculated over net production.*
2. *Operating Costs section on page 9.*
3. *Share of income from associates – pipelines, in the "Non-Operating Costs" section on page 11.*
4. *General and administrative costs section on page 10.*
5. *Finance costs in the "Non-Operating Costs" section on page 11.*
6. *Mainly includes dividends from associates, Frontera's share of income (loss) from associates, income tax, equity tax paid (equity tax was eliminated on December 31, 2017), realized foreign exchange, inventory fluctuation, overlift (settlement) and settlement of asset retirement obligations.*
7. *Production section on page 4.*
8. *Sales volumes D&P excludes E&E as the revenues and costs are capitalized under IFRS.*

Operating netback for the three months ended June 30, 2018, increased by 32% to $26.76/boe from $20.31/boe in the same period of 2017. The increase from the prior year is primarily the result of a higher combined realized price from the improvement in Brent oil benchmarks and lower transportation costs, partially offset by higher production costs from the increase in production at Block 192 in Peru, higher field expenses, maintenance and well servicing activities in Colombia, and higher PAP and cash royalties due to the stronger oil price environment.

Adjusted netback for the three months ended June 30, 2018, increased by 21% to $23.13/boe from $19.13/boe in the same period of 2017. The increase is attributable to the improvement in operating netback partially offset by higher fees paid for suspended pipeline capacity at the Bicentenario system, which was not rendering services to the Company for more days in this quarter compared to the second quarter of 2017.

Adjusted FFO netback for the three months ended June 30, 2018, increased by 49% to $17.53/boe from $11.76/boe in the same period of 2017. The increase is primarily due to the increase in adjusted netback and cash dividends received from associates of $48.4 million offset by an overlift charge for volumes sold but not produced.

In comparison to the first quarter of 2018, operating, adjusted and adjusted FFO netbacks have increased this quarter by 10%, 8%, and 5%, respectively, as a result of higher combined realized prices offset by the increase in production costs per barrel.

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

	Six months ended June 30			
	2018		2017	
	($/boe)	$M	($/boe)	$M
Combined realized price (including realized (loss) gain on risk management contracts) [1]	**54.82**	**597,088**	**46.11**	**564,744**
Production cost	(13.29)	(156,772)	(9.68)	(126,917)
PAP and cash royalties	(1.73)	(20,349)	(0.82)	(10,795)
Transportation cost	(12.25)	(144,513)	(14.08)	(184,687)
Diluent cost	(1.66)	(19,606)	(1.07)	(14,094)
Total operating cost [2]	**(28.93)**	**(341,240)**	**(25.65)**	**(336,493)**
Operating Netback	**25.89**	**255,848**	**20.46**	**228,251**
Fees paid on suspended pipeline capacity [2]	(6.50)	(76,739)	(3.76)	(49,337)
Share of income from associates – pipelines [3]	3.16	37,278	2.13	27,885
Adjusted Netback	**22.55**	**216,387**	**18.83**	**206,799**
General and administrative [4]	(4.09)	(48,221)	(4.10)	(53,804)
Cash finance costs [5]	(1.07)	(12,624)	(0.95)	(12,500)
Other cash costs [6]	—	43	(1.19)	(15,584)
Adjusted FFO Netback	**17.39**	**155,585**	**12.59**	**124,911**
Net production volume (boe/d) [7]	65,178		72,446	
Sales volume (D&P) (boe/d) [8]	60,174		67,665	

References 1 through 8 are consistent with those included in the quarterly netbacks table on page 6.

Operating netback for the six months ended June 30, 2018, increased by 27% to $25.89/boe from $20.46/boe in the same period of 2017. The reasons for the increase during the first half of 2018 are consistent with those factors as described in the variation for the quarter ended June 30, 2018.

Adjusted netback for the six months ended June 30, 2018, increased by 20% to $22.55/boe from $18.83/boe in the same period of 2017. The increase is attributable to the higher operating netback partially offset by increased fees paid for suspended pipeline capacity at the Bicentenario system, which was not rendering services to the Company for more days during the first half of 2018 compared to the same period of 2017.

Adjusted FFO netback for the six months ended June 30, 2018 increased by 38% to $17.39/boe from $12.59/boe in the comparable period of 2017 due to the same reasons as previously described in the analysis for the quarter ended June 30, 2018.

Realized and Reference Price

					Six months ended June 30	
		Q2 2018	Q1 2018	Q2 2017	2018	2017
Reference price						
Brent	($/bbl)	74.97	67.23	50.79	71.16	52.67
Average realized prices						
Realized oil price	($/bbl)	70.44	63.43	46.72	67.45	48.66
Realized natural gas price	($/Mcf)	4.05	4.08	3.79	4.07	3.76
Realized natural gas price	($/boe)	23.10	23.25	21.63	23.18	21.45
Combined realized price before risk management contracts	**($/boe)**	**67.27**	**59.75**	**44.51**	**64.02**	**45.42**
Realized (loss) gain on risk management contracts	($/boe)	(11.12)	(8.98)	0.57	(10.19)	(0.44)
Other revenue [1]	($/boe)	0.55	1.59	1.20	0.99	1.13
Combined realized price after risk management contracts	**($/boe)**	**56.70**	**52.36**	**46.28**	**54.82**	**46.11**

1. Mainly includes revenue from infrastructure and other assets. Includes revenue from PEL until its disposal on April 19, 2018

For the three and six month periods ended June 30, 2018, combined realized price after risk management contracts increased by 23% and 19%, respectively, compared to the same periods of 2017. This was primarily driven by the increase in Brent benchmark oil prices and better price differentials during the first half of 2018. During this period, International oil prices have risen as a result of strong global demand, supply concerns in major producing countries like Venezuela, Iran and Libya, as well as higher geopolitical risk in the Middle East. In both periods, realized losses on risk management contracts offset the increases as the Company had established hedging positions at lower prices in the prior year in order to provide downside protection following a restructuring transaction in late 2016.

As compared to the first quarter of 2018, combined realized price after risk management contracts increased by 8%, primarily due to a 12% quarter-over-quarter increase in the benchmark for Brent oil prices.

Sales

	Three months ended June 30		Six months ended June 30	
(in thousands of U.S.$)	**2018**	**2017**	**2018**	**2017**
Oil and natural gas sales and other revenue	418,560	270,033	708,094	570,186
Sales of oil and natural gas for trading	166	26,075	2,493	51,346
Total sales	**418,726**	**296,108**	**710,587**	**621,532**
Realized (loss) gain on risk management contracts	(68,613)	3,344	(111,006)	(5,442)
Total sales after realized (loss) gain on risk management contracts [(1)]	**350,113**	**299,452**	**599,581**	**616,090**
Total sales after realized (loss) gain on risk management contracts excluding trading	349,947	273,377	597,088	564,744
$/boe volume sold	56.70	46.28	54.82	46.11

1. Refer to the "Non-IFRS Measures" section on page 13.

Total sales for the three months ended June 30, 2018, increased by $122.6 million, or 41%, to $418.7 million compared with the same period in 2017. This was primarily due to a 51% increase in combined realized prices before risk management contracts and higher volumes sold including one additional cargo that was planned for shipment during the first quarter but not shipped until April 2018. For the six months ended June 30, 2018, total sales increased by $89.1 million, or 14%, to $710.6 million primarily as a result of 41% higher combined realized prices partially offset by lower volumes sold. In both periods, the Company realized losses from the settlement of risk management contracts which partially offset the impact of higher oil prices on total sales.

In Colombia, total sales were $401.9 million for the second quarter of 2018 compared with $284.8 million in the same prior year period. In Peru, total sales were $16.8 million for the second quarter of 2018 compared with $11.3 million in the second quarter of 2017.

The following table describes the various factors that had an impact on the movement in total sales after realized loss on risk management contracts from both the second quarter and first half of 2018 to the comparable periods of 2017:

	Three months ended June 30	Six months ended June 30
(in thousands of U.S.$; YTD analysis in parenthesis)	**2018 - 2017**	**2018 - 2017**
Total sales after realized loss on risk management contracts for the period ended June 30, 2017 [(1)]	**299,452**	**616,090**
Increase due to higher volumes sold of 2,914 boe/d (YTD - 7,491 boe/d lower)	11,803	(61,584)
Decrease due to lower volume of trading 6,298 bbl/d (YTD - 5,857 bbl/d lower)	(25,968)	(49,580)
Higher realized losses on risk management contracts	(71,957)	(105,564)
Increase due to 51% higher combined realized prices before risk management contracts (YTD - 41%)	140,531	203,320
Other revenue decrease	(3,748)	(3,101)
Total sales after realized loss on risk management contracts for the period ended June 30, 2018 [(1)]	**350,113**	**599,581**

1. Refer to the "Non-IFRS Measures" section on page 13.

Total sales reported for previous quarters included in this MD&A are different from those previously reported in our public disclosure as a result of the adoption of IFRS 15 effective January 1, 2018. As a result of this new standard, realized gains and losses on risk management contracts are no longer included in total sales. For further information on this change in presentation, refer to Note 2 of the Interim Financial Statements.

Operating Costs

(in thousands of U.S.$)	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Production cost	82,450	65,390	156,772	126,917
PAP and cash royalties	12,598	4,922	20,349	10,795
Transportation cost	68,935	93,435	144,513	184,687
Diluent cost	10,741	7,225	19,606	14,094
Total operating cost	**174,724**	**170,972**	**341,240**	**336,493**
Average operating cost $/boe production	**29.94**	**25.97**	**28.93**	**25.65**
Fees paid on suspended pipeline capacity	40,835	22,237	76,739	49,337
Purchase of oil and natural gas for trading	163	25,483	1,906	50,455
Inventory valuation	1,852	(3,525)	(7,961)	(3,936)
Overlift (settlement)	22,539	(6,433)	5,520	(25)
Total cost	**240,113**	**208,734**	**417,444**	**432,324**

Total operating costs for the three and six months ended June 30, 2018, increased by 2% and 1% to $174.7 million and $341.2 million from $171.0 million and $336.5 million, respectively, from the comparable periods in 2017. Although total operating costs remained relatively consistent with the prior year periods, the composition of costs changed mainly due to the following:

- Production costs increased by 26% and 24% in the three and six months ended June 30, 2018, respectively, compared with the same periods of 2017 as a result of the increase in production at Block 192, which experienced significant downtime in 2017 and higher field expenses, maintenance and well servicing activities in Colombia.
- PAP and cash royalties increased by 156% and 89% in the three and six months ended June 30, 2018, respectively, compared with the same period of 2017 as a result of higher Brent oil benchmark prices.
- Transportation costs decreased by 26% and 22% in the three and six months ended June 30, 2018, respectively, compared with the same periods of 2017 due to the higher usage of an alternative transportation pipeline system with reduced tariffs. Specifically, when the Bicentenario system was not rendering services to the Company, volumes were transported through the Ocensa pipeline and lower tariff rates were paid. During the second quarter and first half of 2018, the Bicentenario system was not rendering services to the Company for more days as compared with the same prior year periods. This resulted in more volumes shipped using the lower cost alternative.
- Fees paid on suspended pipeline capacity increased by 84% and 56% in the three and six months ended June 30, 2018, respectively, compared with the same periods of 2017 as a result of the Bicentenario system not rendering services to the Company for more days as compared with the same prior year periods.
- Aggregate transportation costs (which includes transportation costs and fees paid on suspended pipeline capacity) decreased by 5% and 6% in the second quarter and first half of 2018, respectively, compared with the same prior year periods primarily as a result of lower total volumes transported and a cost recovery of $5.2 million recognized this quarter relating to the P-135 Settlement Agreement (refer to Commitments section on page 17).

For the three months ended June 30, 2018, total costs increased by 15% to $240.1 million compared with the same prior year period. In addition to the items described above, total costs were impacted by an overlift charge recognized this quarter partially offset by lower purchases of oil and gas for trading activities. For the six months ended June 30, 2018, total costs decreased by 3% to $417.4 million compared to the same period in 2017 primarily due to the significantly lower volumes of oil and gas trading activities partially offset by the factors previously described in total operating costs.

Depletion, Depreciation and Amortization

(in thousands of U.S.$)	Three months ended June 30		Six months ended June 30	
	2018	2017	2018	2017
Depletion, depreciation, and amortization	85,576	97,588	158,249	199,382
$/boe production	14.66	14.82	13.41	15.21

Depletion, depreciation, and amortization expenses ("**DD&A**") for the three and six months ended June 30, 2018, decreased to $85.6 million and $158.2 million compared with $97.6 million and $199.4 million in the comparable periods of 2017. The decrease for both periods is primarily due to lower production volumes and a lower depletable base resulting from impairment charges recognized during 2017.

Impairment Expenses

	Three months ended June 30		Six months ended June 30	
(in thousands of U.S.$)	2018	2017	2018	2017
Impairment of investment in associates	107,660	—	118,876	—
Impairment of assets held for sale - transmission line assets	—	23,159	9,125	23,159
Impairment of oil and gas properties, exploration and evaluation assets, and plant and equipment	2,007	—	2,007	(11,625)
Other	269	—	269	1,178
Total impairment	**109,936**	**23,159**	**130,277**	**12,712**

During the second quarter of 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 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.

During the second quarter of 2017, the Company recognized a total impairment charge of $23.2 million relating to certain non-core assets that were written down to offer prices received as part of the divestment process. For the six months ended June 30, 2017, the Company also recognized an impairment reversal relating to the final recoverable amount on certain assets classified as held for sale.

For further details of the impairment charges, refer to Note 6 of the Interim Financial Statements.

General and Administrative

	Three months ended June 30		Six months ended June 30	
(in thousands of U.S.$)	2018	2017	2018	2017
General and administrative	26,168	26,098	48,221	53,804
$/boe production	4.48	3.96	4.09	4.10

General and administrative expenses ("**G&A**") for the three months ended June 30, 2018, were consistent with the previous quarter. However, as a result of lower production volumes in the second quarter of 2018, G&A of $4.48/boe was higher than the comparable period. For the six months ended June 30, 2018, G&A decreased by 10% to $48.2 million compared with the same period of 2017 primarily due to a reduction in employee-related expenses and the Company's continued efforts to reduce overhead costs. On a per boe basis, G&A for the first half of 2018 remained consistent with the prior year and in line with guidance for 2018.

Restructuring, Severance and Other Costs

	Three months ended June 30		Six months ended June 30	
(in thousands of U.S.$)	2018	2017	2018	2017
Restructuring and other cost	813	731	1,282	731
Severance	741	1,111	3,110	7,057
Total restructuring, severance costs and others	**1,554**	**1,842**	**4,392**	**7,788**

Restructuring, severance and other costs for the three and six months ended June 30, 2018, were $1.6 million and $4.4 million, a decrease of 16% and 44% from the comparable periods in 2017, respectively. This decrease was primarily the result of higher expenses recorded during the first half of 2017, following the completion of the Company's restructuring transaction in November of 2016. In 2018, the Company will continue to invest in initiatives that are expected to deliver structural improvements, particularly in areas relating to controls, compliance and operational efficiencies.

Non-Operating Costs

(in thousands of U.S.$)	Three months ended June 30 2018	Three months ended June 30 2017	Six months ended June 30 2018	Six months ended June 30 2017
Cash finance costs	(6,374)	(6,250)	(12,624)	(12,500)
Non-cash finance (loss) income	(3,125)	(336)	(1,122)	1,017
Total finance costs, net	**(9,499)**	**(6,586)**	**(13,746)**	**(11,483)**
Cash finance costs $/boe production	(1.09)	(0.95)	(1.07)	(0.95)
Share of income from associates - pipelines	19,671	14,505	37,278	27,885
Share of (loss) income from associates - Pacific Infrastructure Ventures Inc. and other	(20)	(4,568)	18,132	6,040
Total share of income from associates	**19,651**	**9,937**	**55,410**	**33,925**
Share of income from associates - pipelines $/boe production	3.37	2.20	3.16	2.13
Foreign exchange (loss) gain	**(8,199)**	**(12,409)**	**10,806**	**(1,163)**
Realized (loss) gain on risk management contracts	(68,613)	3,344	(111,006)	(5,442)
Unrealized (loss) gain on risk management contracts	(3,198)	12,434	14,115	52,579
Total (loss) gain on risk management contracts	**(71,811)**	**15,778**	**(96,891)**	**47,137**
Current income tax expense	(5,454)	(3,535)	(15,783)	(13,569)
Deferred income tax expense	(6,271)	—	(6,688)	—
Total income tax expense	**(11,725)**	**(3,535)**	**(22,471)**	**(13,569)**

Finance Costs, Net

Finance costs include interest expense on the Company's long-term debt, short-term borrowings, finance leases and fees on letters of credit net of interest income received on cash deposits. Total finance costs for the three and six months ended June 30, 2018 were $9.5 million and $13.7 million, a 44% and 20% increase from $6.6 million and $11.5 million, respectively, in the same periods of 2017 resulting from higher accretion expense from receivables and transaction fees relating to the closing of the New LC Facility.

Share of Income from Associates

The Company's share of income from associates for the three and six months ended June 30, 2018, was $19.7 million and $55.4 million, a 98% and 63% increase from $9.9 million and $33.9 million, respectively, in the same periods of 2017. This was primarily due to the Colombian peso ("**COP**") functional currency of certain associates, which appreciated 4% relative to the U.S. dollar ("**USD**").

Foreign Exchange

Foreign exchange loss in the second quarter of 2018 decreased by $4.2 million, or 34%, compared with the same prior year period, primarily due to the impact of the COP's appreciation against the USD on the translation of the Company's net working capital balances.

(Loss) Gain on Risk Management Contracts

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 oil production. As at June 30, 2018, the Company hedged approximately 57% of its estimated production up to and including October 2018. The objective for 2018 is to continue hedging where effective, to provide a base level of cash flow to assure that the Company can execute at least a portion of its capital spending and debt service requirements; however, this is constantly re-evaluated in the context of current prices, market expectations, and changes in the production forecast.

The current hedging portfolio consists of zero-cost collars and call spread instruments. As at June 30, 2018, the Company had outstanding hedge positions for a total of 4.8 MMbbl with average floor and ceiling strike Brent prices of $52.69/bbl and $60.05/bbl, respectively, with a liability representing fair value of $89.3 million.

Type of Instrument	Settlement Month	Benchmark	Notional Amount / Volume (bbl)	Put/Call Strike	Carrying Amount (in thousands of U.S.$)	
					Assets	Liabilities
Collar	July 2018	Brent	1,200,000	52.00 / 59.31	—	23,826
Collar	August 2018	Brent	1,200,000	52.42 / 60.05	—	22,479
Collar	September 2018	Brent	1,200,000	53.42 / 61.63	—	20,296
Collar/ Call Spreads	October 2018	Brent	1,200,000	52.92 / 59.22	—	22,674
Total as at June 30, 2018					—	89,275
Total as at December 31, 2017					—	103,747

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations from the movement of COP relative to USD as a significant portion of capital and operating expenditures are incurred in COP. The Company monitors its exposure to such foreign currency risks and mitigates this risk by entering USD denominated foreign exchange risk management contracts. As at June 30, 2018, the Company had outstanding foreign currency forward contracts for the months of July to December 2018, for a total notional amount of $42.0 million, with a liability representing fair value of $0.4 million.

Type of Instrument	Term	Notional Amount (in thousands of U.S.$)	Par Forward (COP$)	COP equivalent of amount hedged (in thousands of U.S.$)	Carrying Amount (in thousands of U.S.$)	
					Assets	Liabilities
Forward	July 2018 to December 2018	42,000	2,919	122,616,060	—	357
Total as at June 30, 2018					—	357
Total as at December 31, 2017					—	—

Income Tax Expense

The current income tax expense for the second quarter of 2018 was $5.5 million. The current income tax expense for the six months ended June 30, 2018, is $15.8 million, which includes minimum income tax (presumptive tax) of $13.1 million, a tax of $2.4 million coming from the dividends of the investments in associates, and current tax in countries other than Colombia of $0.3 million. In addition, the Company recognized an income tax expense of $6.7 million related to the utilization of the deferred tax asset.

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

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
(in thousands of U.S.$)	2018	2017	2018	2017
Maintenance and development drilling	39,350	30,801	83,133	65,918
Exploration activities (1)	27,660	1,215	52,496	2,186
Facilities and infrastructure	15,857	3,834	23,512	5,255
Administrative assets and other projects	3,946	1,976	6,513	3,266
Total capital expenditures	**86,813**	**37,826**	**165,654**	**76,625**

1. *Net of revenues and costs from E&E assets.*

Capital expenditures for the three and six months ended June 30, 2018, were $86.8 million and $165.7 million, a 130% and 116% increase from $37.8 million and $76.6 million, respectively, in the same periods of 2017. The Company continues to execute on its active exploration and development drilling program with eight rigs in operation during the second quarter, including five in the Quifa heavy oil district, two in the light oil-focused Guatiquia Block, and one in the Llanos 25 Block. A total of 57 development wells were drilled during the first half of 2018 compared to 34 in the same prior year period, including new horizontal oil wells in Quifa during the second quarter. In addition, the Company has invested in the expansion of production infrastructure at various blocks including the construction of facilities to expand water handling capabilities in Quifa, which is expected to be operational during the fourth quarter of 2018. During the second quarter, the Company drilled 24 development wells compared with 17 and 33 wells drilled during the second quarter of 2017 and first quarter of 2018, respectively.

Selected Quarterly Information

		2018		2017				2016	
		Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Operational and financial results									
Net production	(boe/d)	64,140	66,227	64,445	71,068	72,370	72,524	69,432	75,096
Oil production	(boe/d)	59,636	61,352	59,131	65,641	66,448	66,035	62,229	67,128
Natural gas production	(Mcf/d)	25,673	27,788	30,290	30,934	33,755	36,987	41,057	45,418
Oil and natural gas sales	(boe/d)	67,822	52,440	65,481	63,162	64,908	70,452	67,470	81,877
Combined realized price (including realized (loss) gain on risk management contracts)	($/boe)	56.70	52.36	53.26	47.86	46.28	45.95	41.92	40.83
Realized oil and natural gas and other revenue price	($/boe)	67.82	61.34	56.19	47.55	45.71	47.34	43.44	40.83
Realized (loss) gain on risk management contracts	($/boe)	(11.12)	(8.98)	(2.93)	0.31	0.57	(1.39)	(1.52)	—
Brent price	($/bbl)	74.97	67.23	61.46	52.17	50.79	54.57	51.06	46.99
Operating cost	($/boe)	(29.94)	(27.94)	(29.65)	(24.32)	(25.97)	(25.36)	(27.40)	(24.06)
Operating Netback [1]	($/boe)	26.76	24.42	23.61	23.54	20.31	20.59	14.52	16.77
Adjusted Netback [1]	($/boe)	23.13	21.35	21.83	20.68	19.13	18.49	13.89	12.91
Adjusted FFO Netback [1]	($/boe)	17.53	16.64	15.13	12.64	11.76	13.38	2.48	2.55
Total sales after realized (loss) gain on risk management contracts [1]	($M)	350,113	249,468	335,346	307,080	299,452	316,638	269,772	308,705
Net (loss) income [2]	($M)	(184,436)	(3,121)	(32,544)	(141,115)	(51,542)	8,498	4,025,194	(557,068)
Per share – basic [3]	$	(1.84)	(0.03)	(0.33)	(1.41)	(0.52)	0.08	40.25	(88,417.54)
Per share – diluted [3]	$	(1.84)	(0.03)	(0.33)	(1.41)	(0.52)	0.08	40.24	(88,417.54)
Operating EBITDA [1]	($M)	124,667	85,988	105,010	105,885	86,857	92,442	44,275	89,846
Adjusted EBITDA [1]	($M)	122,379	86,654	1,999	44,203	87,389	115,058	(1,967)	37,689
Adjusted FFO [1]	($M)	121,325	34,260	94,695	47,889	46,151	78,760	8,256	43,036
Capital expenditures [4]	($M)	86,813	78,841	111,213	48,563	37,826	38,799	64,707	33,631
Total assets	($M)	2,556,781	2,664,920	2,579,651	2,546,631	2,621,871	2,772,423	2,741,719	2,403,602

1. *Refer to the "Non-IFRS Measures" section on page 13.*
2. *Net (loss) income attributable to equity holders of the Company.*
3. *The basic and diluted weighted average number of common shares are stated on an adjusted post split-split basis.*
4. *Capital expenditures includes sales from E&E assets.*

Over the past eight quarters, the Company's oil and natural gas sales have fluctuated due to changes in production, movements in the Brent benchmark oil price, fluctuations in oil price differentials and realized risk management activities. Trends in the Company's production levels have resulted from natural declines on existing fields, disposals or relinquishment of oil and natural gas properties, and suspension of operations due to unforeseen circumstances, such as community blockades, offset by increasing production from recent operations in Peru. Trends in the Company's net income and loss are also impacted most significantly by changes in risk management activities that fluctuate with changes in forward market prices, DD&A and net impairment charges of oil and natural gas assets, along with significant reductions in corporate financing and administrative costs as the Company exited the restructuring process in November 2016.

Please refer to the Company's previously issued annual and interim management discussion and analysis for further information regarding changes in prior quarters.

Non-IFRS Measures

This report contains the following financial terms that do not have standardized definitions in IFRS: Operating and Adjusted EBITDA, operating netback, adjusted netback, adjusted FFO netback, adjusted FFO and Total sales after realized (loss) gain on risk management contracts. The Company believes that these financial measures provide useful information to investors and shareholders, as management uses this information to analyze operating performance and liquidity. 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 and Adjusted EBITDA

Management believes that EBITDA is a commonly used measure to assess operational profitability before the impact of different tax jurisdictions, financing methods, capital structure and the application of accounting policies impacting DD&A and impairment.

- Operating EBITDA represents the operating results of the Company's primary business, excluding the effects of financing costs, income taxes, DD&A, fees paid on suspended pipeline capacity, other investments (such as infrastructure assets), certain non-cash items (such as impairments, unrealized foreign exchange gains and losses, and share-based compensation), risk management activities, dispositions of capital assets and other unusual or non-recurring items.
- Adjusted EBITDA modifies Operating EBITDA by including the results from the Company's other investments (such as infrastructure assets) including fees paid on suspended pipeline capacity, risk management activities and other items as disclosed below.

A complete reconciliation of Operating and Adjusted EBITDA to net loss is as follows:

	Three months ended June 30		Six months ended June 30	
(in thousands of U.S.$)	2018	2017	2018	2017
Net loss [1]	**(184,436)**	**(51,542)**	**(187,557)**	**(43,044)**
Adjustments				
Income tax expense	11,725	3,535	22,471	13,569
Depletion, depreciation and amortization	85,576	97,588	158,249	199,382
Impairment	109,936	23,159	130,277	12,712
Finance costs, net	9,499	6,586	13,746	11,483
Restructuring, severance costs and others	1,554	1,842	4,392	7,788
Equity tax	—	—	—	11,694
Other loss (income), net	699	(5,350)	1,303	(7,848)
Foreign exchange unrealized loss (gain)	11,351	11,571	(10,323)	(3,289)
Reclassification of currency translation adjustments	50,847	—	50,847	—
Net loss on extinguishment debt	25,628	—	25,628	—
Adjusted EBITDA	**122,379**	**87,389**	**209,033**	**202,447**
Unrealized loss (gain) on risk management contracts	3,198	(12,434)	(14,115)	(52,579)
Share of income from associates	(19,651)	(9,937)	(55,410)	(33,925)
Loss (gain) attributable to non-controlling interest	(20,722)	(1,469)	(7,943)	9,314
Share based compensation	1,780	233	2,834	253
Foreign exchange realized (gain) loss	(3,152)	838	(483)	4,453
Fees paid on suspended pipeline capacity	40,835	22,237	76,739	49,337
Operating EBITDA	**124,667**	**86,857**	**210,655**	**179,300**

1. Net loss attributable to equity holders of the Company.

Netbacks

Management believes that netback is a useful measure to assess the net profit after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and natural gas industry to analyze financial and operating performance expressed as profit per barrel.

- Operating netback represents combined realized price per barrel, including realized gain or loss from risk management contracts, less production costs, PAP and cash royalties, transportation and diluent costs, as well as showing how efficient the Company is at extracting and selling its product.
- Adjusted netback represents Operating Netback plus the results from corporate investments, such as pipeline investments that are in addition to oil and natural gas production and the take-or-pay fees paid on suspend pipeline capacity.
- Adjusted funds flow from operations netback ("**Adjusted FFO Netback**") represents adjusted netback less corporate cash expenses (G&A and cash finance costs) and other cash items (primarily dividends and Frontera's share of income from associates, income tax, equity tax paid, realized foreign exchange, inventory fluctuations, overlift (settlement) and settlement of asset retirement obligations).

Refer to the "Netbacks" section on page 6.

Adjusted FFO

Adjusted FFO is a non-IFRS financial measure that adjusts an IFRS measure, net cash provided (used) by operating activities, for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include differences in timing of cash flows related to accounts receivable and accounts payable, which management believes reduces comparability among periods. The indicator also excludes settlement of asset retirement obligations, one-time expenses for the Company not related to ongoing operations such as restructuring, severance and other costs, and loss (gain) from relinquished assets.

A complete reconciliation of Adjusted FFO to net cash provided by operating activities is as follows:

	Three months ended June 30		Six months ended June 30	
(in thousands of U.S.$)	**2018**	**2017**	**2018**	**2017**
Net cash provided by operating activities	108,400	12,055	138,665	78,981
Changes in non-cash working capital	11,371	31,972	12,478	37,860
Funds Flow from Operations	**119,771**	**44,027**	**151,143**	**116,841**
Restructuring and severance costs	1,554	1,842	4,392	7,788
Settlement of assets retirement obligations	—	282	50	282
Adjusted FFO	**121,325**	**46,151**	**155,585**	**124,911**

Total sales after realized (loss) gain on risk management contracts

Total sales after realized (loss) gain on risk management contracts is a non-IFRS subtotal that adjusts total sales to include realized gains and losses from oil risk management contracts. This is a useful indicator for management as the Company hedges a portion of oil production using derivative commodity instruments in order to manage exposure to price volatility. This metric allows the Company to report its realized net sales after factoring in these risk management activities.

Refer to the “Sales” section on page 8.

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 the operation of our business and existing contingencies; and
- Debt service requirements relating to existing and future debt.

The Company expects to fund its anticipated cash requirements and strategic objectives using current cash and working capital balances, funds flow from operations, and available debt and credit facilities. In accordance with the Company’s investment policy, available cash balances are held in high interest savings accounts, term deposits and Colombian mutual funds with high credit ratings and short-term liquidity.

As at June 30, 2018, the Company had total cash balances of $730.1 million, an increase of $86.0 million as compared to December 31, 2017. This increase was primarily due to $108.4 million of cash generated from operating activities and the receipt of gross cash proceeds from the divestments of PEL ($55.6 million) and assets in Papua New Guinea ($57.0 million). The Company also generated $41.7 million from financing activities primarily due to the issuance of $350.0 million Unsecured Notes, which resulted in net cash proceeds of $60.0 million after repurchasing the Secure Notes and transaction costs. These factors were partially offset by net capital expenditures of $165.7 million in the first half of 2018 as the Company continued to expand development and production facilities across its core assets.

As at June 30, 2018, the Company had a working capital surplus of $317.4 million, an increase of $7.3 million as compared to December 31, 2017. Working capital balances in conjunction with future funds flow from operations and available credit facilities are sufficient to support the Company’s normal operating requirements and commitments on an ongoing basis.

Senior Unsecured Notes

The Company's long-term borrowing consists of $350.0 million of the Unsecured Notes in the aggregate amount of $350.0 million, issued on June 25, 2018. 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, beginning on December 25, 2018. The Unsecured Notes will mature in June 2023, unless earlier redeemed or repurchased. Concurrent with the offering, the net proceeds of the Unsecured Notes were partially used to repurchase, at a premium and including accrued interest, the total obligation under the Company's previously issued 10% Secured Notes, which were set to mature in 2021. The remaining proceeds will be used for general corporate purposes. The carrying value of the Secured Notes at the redemption date was $250.0 million and as a result, the Company recorded a loss on extinguishment of $25.6 million representing the tender and consent payments.

The refinancing transaction successfully extended the maturity and reduced the Company's average cost of debt.

Letter of Credit Facility

On May 17, 2018, the Company replaced its amended and restated Secured LC Facility with the $100.0 million New LC Facility with a maturity date of May 17, 2020. As at June 30, 2018, the outstanding letters of credit issued and maintained under the New LC Facility for exploration and operational commitments totalled $93.0 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 New LC Facility, interest accrues at 6% per annum. If any event of default exists, the applicable rate will increase by an additional 2% per annum until such default is cured.

Additional information on the terms of the New LC Facility is included in "Note 20 - Commitments and Contingencies" of the Interim Financial Statements.

Covenants

The Unsecured Notes are senior, unsecured and rank equal in right of payment with all of our 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 New 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 3:1 and the consolidated fixed charge ratio(2) is greater than or equal to 2.5:1. 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. As at June 30, 2018, the Company is in compliance with such covenants.

As a result of the financing transaction, the Company has achieved a more flexible set of covenants that are reflective of current market standards while also releasing the security on the Company's assets.

1. *Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the Notes Indenture as the Consolidated Total Indebtedness as of such date divided by Consolidated Adjusted EBITDA for the most recently ended period of four consecutive fiscal quarters. Consolidated Adjusted EBITDA is defined as the Consolidated Net Income (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense, and abandonment costs.*
2. *Consolidated Fixed Charge Ratio is the Consolidated Adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period as defined in the Indenture.*

Guarantees

The Company has various guarantees in place in the normal course of business. As at June 30, 2018, in addition to letters of credit drawn from the New LC Facility of $93.0 million, the Company had also issued $3.5 million of cash collateralized letters of credit and endorsed term deposits in COP for $0.1 million. At the end of the period, total guarantees for exploration and operational commitments totalled $96.6 million.

Commitments

The following table summarizes the Company's estimated commitments, on an undiscounted basis, as at June 30, 2018:

(in thousands of U.S.$)	2018	2019	2020	2021	2022	2023 and Beyond	Total
Financial							
Debt	—	—	—	—	—	350,000	350,000
Finance lease	4,601	5,329	6,129	1,133	—	—	17,192
Transportation Commitments							
Oleoducto de los Llanos Orientales S.A. Ship-or-Pay Agreement	25,099	50,197	30,929	1,158	—	—	107,383
Bicentenario Ship-or-Pay Agreements (1)	4,152	8,305	8,305	8,305	8,305	14,721	52,093
Ocensa P-135 Ship-or-Pay Agreement	33,536	67,071	67,071	67,071	67,071	168,148	469,968
Pacific Infrastructure Ventures Inc. Take-or-Pay Agreements	19,152	41,653	41,653	41,653	203	—	144,314
Transportation and processing commitments (1)	28,923	50,099	48,813	48,813	48,745	185,587	410,980
Exploration Commitments							
Minimum work commitments	103,009	32,100	54,615	27,546	—	—	217,270
Other Commitments							
Operating purchases and leases	61,113	18,772	18,544	17,416	10,921	7,325	134,091
Community obligations	6,291	525	525	525	525	1,051	9,442
Total	**285,876**	**274,051**	**276,584**	**213,620**	**135,770**	**726,832**	**1,912,733**

1. Excludes commitments related to terminated transportation agreements (see below).

Ocensa P-135 Project Arbitration Settlement

The Company and Ocensa reached a successful settlement agreement in an arbitration on tariffs and monetary conditions relating to transportation contracts entered into with Ocensa concerning the P-135 Project (the "**P-135 Settlement Agreement**"). Under the terms of the P-135 Settlement Agreement, which was approved by the arbitrators, the Company has committed to ship 30,000 barrels of oil per day at $6.3601 per barrel (adjusted at 2.57% inflation per year until 2023 and thereafter, pursuant to applicable regulation) on the Ocensa P-135 Project through June 2025. The original terms of the contract were for the shipment of 30,000 barrels of oil per day at $8.7729 per barrel (adjusted at 2.57% inflation per year).

The impact of the P-135 Settlement Agreement will reduce Frontera's future transportation commitments over the life of the contract. As at June 30, 2018, prior to the P-135 Settlement Agreement, total commitments for the Ocensa P-135 Project were $648.3 million, which have been reduced to $470.0 million to reflect the settlement tariff terms.

During the second quarter of 2018, the Company recognized a recovery of transportation costs in the amount of $5.2 million ($0.89 per barrel) relating to the difference between the tariff rate of $6.3601 per barrel included in the P-135 Settlement Agreement and $6.91 per barrel as previously agreed to under a temporary payment agreement.

Additional information on the Ocensa P-135 Project and the arbitration process is included in "Note 24 - Commitments and Contingencies" of the 2017 Annual Financial Statements.

Termination of Transportation Contracts

On July 13, 2018, the Company announced that it had exercised its rights to terminate its contracts with CENIT to transport oil through the CLC pipeline and with Bicentenario to transport oil through the BIC pipeline. As a consequence of these terminations, the Company is no longer contractually committed to payments of ship-or-pay fees between July 12, 2018 and October 2028 through the CLC pipeline, and between July 12, 2018 and June 2024 through the BIC pipeline. As at June 30, 2018, total commitments of $1.36 billion under these now-terminated contracts were excluded from the commitments table above.

- The CLC pipeline, which connects the BIC pipeline to the Coveñas Export Terminal, has suspended transport rendered to the Company for more than 180 consecutive calendar days, which is a termination event under the Company's transportation agreement with CENIT. Under the agreement, the Company had a commitment to ship 47,333 barrels of oil per day through the pipeline for which CENIT charges $3.19 per barrel, between now and October 2028.
- The BIC pipeline, which operates between Araguaney and Banadia where it connects to the CLC pipeline, has not transported the Company's oil for more than six uninterrupted months due to a justifiable event, which is a termination event under the transportation agreement with Bicentenario. Under the agreement, the Company had a commitment to ship 47,333 barrels of oil per day through the pipeline at $7.56 per barrel, between now and June 2024.

During the terms of the contracts with both CENIT and Bicentenario, service has been suspended approximately 60% of the time. For the three and six months ended June 30, 2018, the fees paid relating to the periods of disrupted capacity on both pipelines were $40.8 million and $76.7 million, respectively (2017: $22.2 million and $49.3 million, respectively).

The Company continues to have take-or-pay contracts for storage and offloading facilities with Bicentenario, not included in the cancellation of the transportation contracts for $52.1 million and $158.1 million with the BIC and CLC pipelines, respectively. In addition, the take-or-pay of the Monterey-Araguaney pipeline, which connects the Oleoducto de los Llanos Orientales S.A. ("**ODL**") and Bicentenario pipelines, has commitments of $117.1 million.

On July 16, 2018 and July 17, 2018, the Company received notices from Bicentenario and CENIT, respectively, disputing the grounds for the termination of the above-referenced agreements which the Company vigorously disputes. As at July 31, 2018, the Company had issued $64.4 million of standby letters of credit with Bicentenario listed as the beneficiary. The Company has transportation agreements in place to ensure sufficient capacity for the evacuation and sale of its oil production in Colombia.

Puerto Bahia Equity Contribution Agreement

On October 4, 2013, Pacinfra Holding Ltd. ("**Pacinfra**", a subsidiary of the Company), Pacific Infrastructure Ventures Inc. ("**PIV**"), Sociedad Portuaria Puerto Bahia S.A. ("**Puerto Bahia**") (a subsidiary of PIV, Note 13 of the Interim Financial Statements) and Wilmington Trust, National Association (as Collateral and Administrative Agent), entered into an equity contribution agreement, pursuant to which Pacinfra and PIV 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.

During the period ended June 30, 2018, Pacinfra and PIV received deficiency notices, requiring both companies fund a total amount of $30.5 million to Puerto Bahia. On May 31, 2018, Pacinfra advanced these funds under a new shareholder loan agreement (Note 14 of the Interim Financial Statement).

IFC Termination and the Bicentenario Put Option

On October 13, 2017, the Company entered into an agreement to acquire the remaining 36.36% ownership of Pacific Midstream Limited ("**PML**") from International Finance Corporation and related funds (the "**IFC**"), for cash consideration of $225.0 million. Effective July 6, 2018, the Company terminated this agreement. As a result of the termination, the Company is required to pay the IFC a $5.0 million break fee, which was recognized as an expense in the second quarter.

Pursuant to an agreement among the shareholders of PML in 2014, PML has an option, that is exercisable at the discretion of the IFC and solely in the event the Bicentenario pipeline is non-operational for six consecutive months; as a result, the Bicentenario take or pay contracts with the Company's affiliates or Ecopetrol S.A. affiliates are terminated ("**IFC Bicentenario Put Option**"). The option requires the Company to purchase PML's interest in Bicentenario at a price equal to $280.0 million, adjusted for Bicentenario's total cash dividend payments to PML, and repayment of existing subordinated loans with the Company. As at June 30, 2018, the IFC Bicentenario Put Option exercise price was approximately $85.0 million and was determined to be out of the money.

Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. Since the outcome of these matters is uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters, or any amount that may be required to pay by reason thereof, would have a material impact on its financial position, results of operations or cash flows.

Except as noted above, no material changes have occurred with respect to the matters disclosed in "Note 24 - Commitments and Contingencies" of the 2017 Annual Financial Statements.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at July 31, 2018:

	Number
Common Shares [(1)]	99,981,564
Deferred Share Units ("**DSUs**") [(2)]	128,911
Restricted Share Units ("**RSUs**") [(3)]	1,342,174

1. *On June 26, 2018, the Company completed a two-for-one share split with shareholders of record receiving an additional common share for every share held. All related share and per share information has been updated to reflect the post-split share count.*
2. *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, in Common Shares, cash or a combination thereof. Only directors are entitled to receive DSUs.*
3. *RSUs are granted with vesting conditions (typically based on continued service or achievement of personal or corporate objective). 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, in Common Shares, cash or a combination thereof. Vesting of RSUs is determined by the Compensation and Human Resources Committee in its sole discretion and specified in the Award agreement pursuant to which the RSU is granted.*

The Company does not have shares subject to escrow restrictions or pooling agreements.

On July 13, 2018, the Company received approval from the TSX to purchase up to 3,543,270 Common Shares over a twelve-month period commencing on July 18, 2018, under a NCIB. The amount eligible for purchase under the NCIB represents approximately 3.5% of the Company's issued and outstanding Common Shares of 100,011,664 as at June 30, 2018. Between July 18, 2018 and July 31, 2018, the Company has purchased for cancellation 30,100 Common Shares at a total cost of $0.4 million.

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, 2018, and December 31, 2017, and for the three and six months ended June 30, 2018, and 2017:

(in thousands of U.S.$)		Accounts Receivable	Accounts Payable	Commitments[1]	Cash Advance[2]	Loans / Debentures Receivable[2]	Interest Receivable[2]
ODL	2018	2,416	592	107,383	—	—	—
	2017	421	231	130,303	—	—	—
Bicentenario	2018	14,903	—	52,093	87,278	—	—
	2017	12,660	469	902,375	87,278	—	—
PIV	2018	7,887	1,640	144,313	17,741	107,013	30,813
	2017	5,926	1,598	158,179	17,741	76,552	26,331
Interamerican	2018	147	—	—	—	2,224	529
	2017	145	72	—	—	2,224	362
CGX Energy Inc.	2018	535	—	—	—	18,151	1,959
	2017	120	—	—	—	16,122	1,516

		Three Months Ended June 30			Six Months Ended June 30		
(in thousands of U.S.$)		Sales	Purchases / Services	Interest Income[2]	Sales	Purchases / Services	Interest Income[2]
ODL	2018	350	9,584	—	1,359	21,546	—
	2017	1,003	12,084	—	2,000	24,349	—
Bicentenario	2018	—	24,700	—	—	52,798	—
	2017	—	31,657	—	—	67,663	—
PIV	2018	—	6,471	2,430	—	12,804	4,483
	2017	—	6,806	2,063	—	14,102	4,050
Interamerican	2018	—	—	83	3	2	167
	2017	—	5	84	333	21	167
CGX Energy Inc.	2018	158	—	111	309	—	443
	2017	—	—	173	—	—	331

1. Excludes commitments related to terminated transportation agreements (refer to Commitments section on page 17).
2. Amounts presented based on contractual payment obligations, prior to impairments.

For details about significant changes to related party transactions, refer to the "Commitments" section on page 17.

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 2017 Annual Financial Statements, 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. Recent accounting pronouncements of significance or potential significance are described in Note 2 of the Interim Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the Interim Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss and the related disclosure of contingent assets and liabilities included in the consolidated financial statements. The Company evaluates its estimates on an ongoing basis. The estimates are based on historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. These estimates form the basis for making judgments about the carrying value of assets and liabilities and the reported amounts of revenues and other items. 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, 2018, 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

Boe Conversion

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

Abbreviations

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

bbl	Oil Barrels
bbl/d	Barrels of oil per day
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
CPI	Incremental production contract
D&P	Development and producing
E&E	Exploration and evaluation
Mbbl	Thousand of oil barrels
MMbbl	Million of oil barrels
Mcf	Thousand cubic feet
PAP	High-price participation payments
Q	Quarter
YTD	Year to date
$	U.S. dollars
$M	Thousand U.S. dollars
$MM	Million U.S. dollars