MANAGEMENT DISCUSSION & ANALYSIS

November 7, 2018
For the three and nine months ended September 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

Beginning in the third quarter of 2018, the Company changed the composition and terminology of certain non-IFRS measures and eliminated other metrics that are no longer considered in its assessment of operational and financial performance. These changes resulted from a comprehensive review of key performance disclosures to improve the clarity and comparability of the Company's results amongst its industry peer group in Canada and Latin America. For comparison purposes, all corresponding changes have been made for all prior periods presented herein. Refer also to the "Non-IFRS Measures" section on page 16 for additional details on these changes.

*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 nine months ended September 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 16.*

*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 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

		Q3 2018	Q2 2018	Q3 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Operational Results						
Oil production	(bbl/d)	54,436	59,636	65,641	58,449	66,039
Natural gas production	(boe/d)	4,122	4,504	5,427	4,498	5,942
Net production [1]	(boe/d) [2]	58,558	64,140	71,068	62,947	71,982
Oil and gas sales and other revenue	($/boe)	68.02	67.82	47.55	66.03	47.12
Realized (loss) gain on risk management contracts	($/boe)	(10.02)	(11.12)	0.31	(10.13)	(0.44)
Royalties	($/boe)	(2.72)	(2.04)	(0.70)	(2.16)	(0.82)
Diluent cost	($/boe)	(1.89)	(1.74)	(1.21)	(1.83)	(1.17)
Net sales realized price [3]	($/boe)	53.39	52.92	45.95	51.91	44.69
Production cost [4]	($/boe)	(15.81)	(14.13)	(10.85)	(14.08)	(10.07)
Transportation cost [4]	($/boe)	(13.77)	(11.81)	(11.77)	(12.73)	(13.31)
Operating netback [5]	($/boe)	23.81	26.98	23.33	25.10	21.31
Financial Results						
Oil and gas sales and other revenue	($M)	382,189	418,560	276,345	1,090,283	846,531
Realized (loss) gain on risk management contracts	($M)	(56,297)	(68,613)	1,792	(167,303)	(3,650)
Royalties	($M)	(15,280)	(12,598)	(4,047)	(35,629)	(14,842)
Diluent cost	($M)	(10,647)	(10,741)	(7,052)	(30,253)	(21,146)
Net sales [5]	($M)	299,965	326,608	267,038	857,098	806,893
Net income (loss) [6]	($M)	45,105	(184,436)	(141,115)	(142,452)	(184,159)
Per share – basic and diluted [7]	$	0.45	(1.84)	(1.41)	(1.42)	(1.84)
General and administrative	($M)	22,962	26,168	26,569	71,183	80,373
Operating EBITDA [5]	($M)	93,455	124,667	105,885	304,110	285,184
Cash provided by operating activities	($M)	189,352	108,400	110,306	328,017	189,287
Capital expenditures [8]	($M)	124,029	86,813	48,563	289,683	125,188
Cash and cash equivalents – unrestricted	($M)	586,578	550,840	500,643	586,578	500,643
Restricted cash short-and long-term	($M)	199,906	179,248	99,248	199,906	99,248
Total cash	($M)	786,484	730,088	599,891	786,484	599,891
Debt and obligations under finance lease	($M)	352,330	352,806	270,222	352,330	270,222

1. Net production represents the Company's working interest volumes, after 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. Per boe is calculated using sales volumes (D&P).
4. Per boe is calculated using net production after royalties.
5. Refer to the "Non-IFRS Measures" section on page 16. This section also includes a description and details for all per boe metrics included in operating netback.
6. Net income (loss) attributable to equity holders of the Company.
7. The basic and diluted weighted average number of Common Shares are stated on an adjusted post-split basis.
*8. Capital expenditures includes sales and costs from Exploration and Evaluation ("**E&E**") assets.*

Highlights for the Third Quarter of 2018

Changes to Non-IFRS Measures

- Beginning in the third quarter of 2018, the Company changed the composition and terminology of certain non-IFRS measures and eliminated other metrics that are no longer considered in its assessment of operational and financial performance. These changes resulted from a comprehensive review of key performance disclosures to improve the clarity and comparability of the Company's results amongst its industry peer group in Canada and Latin America. Refer also to the "Non-IFRS Measures" section on page 16.

Financial and Operational Results

- Net production averaged 58,558 boe/d during the third quarter of 2018, a decrease of 18% and 9% from the same period in 2017 and the second quarter of 2018, respectively. Net production in the quarter was primarily impacted by pipeline issues in Peru which resulted in a suspension of production at Block 192 until early September.
- Oil and gas sales and other revenue for the third quarter of 2018 were $382.2 million, an increase of 38% compared to the prior year period and 9% lower than the second quarter of 2018. Net sales for the third quarter of 2018 were $300.0 million, an increase of 12% compared to the prior year period and 8% lower than the second quarter of 2018.
- Operating netback for the quarter was $23.81/boe, 2% higher than $23.33/boe reported in the third quarter of 2017 and 12% lower than the previous quarter's operating netback of $26.98/boe.
- Net income for the third quarter was $45.1 million ($0.45/share, basic) compared with a net loss of $141.1 million ($1.41/share, basic) in the same quarter of 2017, and a net loss of $184.4 million ($1.84/share, basic) in the previous quarter.
- Operating EBITDA was $93.5 million for the third quarter of 2018, a decrease of 12% compared to $105.9 million in the same period of 2017. In comparison to the previous quarter, operating EBITDA decreased by 25% from $124.7 million.
- The Company generated $189.4 million from operating activities in the quarter compared to $110.3 million in the same prior year period, contributing to a strong balance sheet with a total cash position of $786.5 million at September 30, 2018.
- Capital expenditures during the quarter were $124.0 million, with a total of 37 development wells drilled.

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 Oleoducto Bicentenario de Colombia S.A.S. ("**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. At the time of their termination, the contracts represented $1.35 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 rejects.

Pacific Midstream Limited ("PML") Update

- On September 11, 2018, the International Finance Corporation and related funds (the "**IFC**") provided a form of notice exercising PML's BIC Put Option, which requires the Company to purchase, from PML, its ownership interest in the BIC pipeline. When completed, the Company's aggregate ownership in the BIC pipeline would increase to 43.03% (currently 26.39%) at a net cost expected to be approximately $34.0 million after the proceeds of the purchase are distributed by PML to its shareholders (gross purchase price of $84.8 million).
- On October 19, 2018, the proceeds from the sale of Petroelectrica de los Llanos Ltd. ("**PEL**"), which had been escrowed during the agreement with the IFC on the acquisition of their interest in PML, were released to the Company. As a result, $45.0 million became unrestricted cash, with the balance of $5.0 million paid to the IFC as a break fee on the termination of the agreement.

Exploration Discovery

- The Acorazado-1 exploration well was drilled to a total measured depth of 15,470 feet (15,197 feet true vertical depth) and encountered a number of potential hydrocarbon zones in the target Mirador formation reservoir. The results of the tests confirmed the pre-drill model of the Acorazado field as an extension of the Cusiana Field and maintained the Company's 100% track record of discoveries in Colombia during 2018.

2. GUIDANCE

The Company has re-affirmed its operating EBITDA guidance range of $400-$450 million for 2018, and updated annual guidance for net production, capital expenditures, and production costs per boe. The guidance for transportation cost per boe was also maintained, while general and administrative was lowered by 5% at the midpoint to reflect the realized benefits of various cost saving initiatives executed during the year.

Annual net production guidance for 2018 was revised and lowered by 5% (at the midpoint) and is now expected to average in the range of 63,000-65,000 boe/d. This revision is due to several factors including higher than planned royalty volumes paid in-kind as high-price participation payments ("**PAP**") (which continue to escalate with rising oil prices), suspension of production from Block 192 in Peru due to a force majeure event on the NorPeruano pipeline, community issues that disrupted operations in both Peru and Colombia, and the re-sequencing of certain capital projects.

The changes to the capital program also resulted in a lowering of capital expenditure guidance by 5% (at the midpoint) to $450 million from $475 million. The Company continues to take a disciplined approach to the development of its assets which has delayed certain planned projects, and the reduced forecast also reflects capital cost and efficiency improvements achieved this year.

Production cost guidance is increased to a midpoint value of $14.25/boe (from $13.00/boe), to reflect lower daily production volumes and inflationary pressures due to higher oil prices. The Company also experienced higher costs from the additional workovers during the force majeure event in Block 192. The servicing and maintenance activities took place while service on the NorPeruano pipeline was suspended in order to restart operations at higher production rates.

General and administrative cost guidance for the year was decreased by 5% to a midpoint of $100 million (from $105 million), to reflect the benefit of recent cost savings initiatives.

The following table reports the actual results for the nine month period ending September 30, 2018 against the current and previous guidance.

		2018 Guidance[1]		
		Revised [2]	**2018 YTD**	**Previous[3]**
Average annual net production	(boe/d)	63,000 to 65,000	**62,947**	65,000 to 70,000
Capital expenditures	($MM)	440 to 460	**290**	450 to 500
Production cost	($/boe)	14.00 to 14.50	**14.08**	12.00 to 14.00
Transportation cost[4]	($/boe)	12.50 to 13.50	**12.73**	12.50 to 13.50
Operating EBITDA	($MM)	400 to 450	**304**	400 to 450
General and administrative	($MM)	95 to 105	**71**	100 to 110

1. *The guidance for operating EBITDA, general and administrative, and capital expenditures are aggregate ranges for the year.*
2. *Current guidance assumes $73/bbl Brent, and realized oil price differential of $5.00/bbl.*
3. *Previous guidance was revised on August 2, 2018 assuming $70/bbl Brent, and realized oil price differential of $5.00/bbl to $5.50/bbl.*
4. *Guidance for transportation cost excludes the impact of fees paid on suspended pipeline capacity.*

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average daily production by total field, gross production before royalties 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	**Q3 2018**	**Q3 2017**	**Q3 2018**	**Q3 2017**	**Q3 2018**	**Q2 2018**	**Q3 2017**	**YTD 2018**	**YTD 2017**
Light and medium oil	30,680	37,545	29,121	35,996	26,949	28,574	33,105	27,548	33,815
Heavy oil	47,063	46,491	28,534	28,090	23,497	23,867	25,731	24,139	27,024
Natural gas	4,768	6,139	4,122	5,427	4,122	4,504	5,427	4,498	5,941
Total production Colombia	**82,511**	**90,175**	**61,777**	**69,513**	**54,568**	**56,945**	**64,263**	**56,185**	**66,780**
Producing fields in Peru (2)									
Light and medium oil	6,152	10,198	4,616	7,898	3,990	7,195	6,805	6,762	5,202
Total production Peru	6,152	**10,198**	4,616	**7,898**	**3,990**	**7,195**	**6,805**	**6,762**	**5,202**
Total production	**88,663**	**100,373**	**66,393**	**77,411**	**58,558**	**64,140**	**71,068**	**62,947**	**71,982**

1. *Gross working interest production before royalties.*
2. *Beginning in Q3 2018, the Company now includes the volumes produced from the service contract in Block 192 as gross production before royalties. This change has been applied to all periods presented herein. Refer also to the "Peru Royalties - Block 192 Contract" section on page 6 for additional information.*

Net production for the third quarter of 2018 decreased by 18% compared to the same prior year quarter primarily due to natural declines on some of the Company's mature fields in Colombia, higher volumes paid in-kind for PAP due to rising oil prices and downtime associated with force majeure on the NorPeruano pipeline in Peru. Three months of downtime related to the pipeline issues resulted in a 5,700 bbl/d impact on production for the quarter. The NorPeruano pipeline was repaired in early September, allowing operations to restart on Block 192, which reached planned production levels above 9,000 bbl/d by the end of the period.

Net production for the nine months ended September 30, 2018 decreased by 13% over the same prior year period, primarily due to natural declines on some of the mature fields in Colombia and higher volumes paid in-kind for PAP due to rising oil prices. Net production during the year was also impacted by temporary water injection restrictions in the Casimena block and a community blockade in the first quarter of 2018 at the Cubiro block. The community dispute in the Cubiro block was resolved during the second quarter of 2018 and consequently had a positive impact on third quarter production due to re-pressurization of the reservoir while the fields were shut-in. In Peru, the Company has increased production on a year-over-year basis despite the pipeline issues, as Block 192 has been operational for more days in 2018.

In comparison to the second quarter of 2018, net production was 9%, or 5,582 boe/d, lower during the third quarter. This quarter-over-quarter decrease was primarily the result of the pipeline issues noted in Peru, as Block 192 was shut down for most of the quarter. Production in Colombia also declined as a result of higher volumes paid in-kind for PAP due to rising oil prices.

Production reconciled to sales volumes

		Q3 2018	Q2 2018	Q3 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Gross production before royalties	**(boe/d)**	**66,393**	**72,026**	**77,411**	**70,732**	**78,129**
Royalties in-kind Colombia	(boe/d)	(7,208)	(6,668)	(5,250)	(6,647)	(5,458)
Royalties in-kind Peru [1]	(boe/d)	(627)	(1,218)	(1,093)	(1,138)	(689)
Net production	**(boe/d)**	**58,558**	**64,140**	**71,068**	**62,947**	**71,982**
Oil inventory (build) draw	(boe/d)	(805)	1,521	(4,930)	(2,164)	(2,676)
Overlift	(boe/d)	5,383	3,493	14	1,936	7
E&E assets volumes sold [2]	(boe/d)	(898)	(979)	(1,075)	(1,014)	(1,343)
Other inventory movements [3]	(boe/d)	(1,167)	(353)	(1,915)	(1,229)	(1,823)
Sales volumes	**(boe/d)**	**61,071**	**67,822**	**63,162**	**60,476**	**66,147**
Oil sales volumes	(boe/d)	56,972	63,283	57,808	56,001	60,419
Natural gas sales volumes	(boe/d)	4,099	4,539	5,354	4,475	5,728
Inventory balance						
Colombia	(bbl)	65,497	54,292	273,606	65,497	273,606
Peru	(bbl)	1,481,916	1,401,511	696,982	1,481,916	696,982
Crude oil inventory ending balance	**(bbl)**	**1,547,413**	**1,455,803**	**970,588**	**1,547,413**	**970,588**

1. *The Company reports the share of production retained by the government of Peru as royalties paid in-kind. Refer also to the "Peru Royalties - Block 192 Contract" section below for additional information.*
2. *Volumes from E&E assets are excluded from total sales volumes because E&E revenues and costs are capitalized under IFRS.*
3. *Mainly corresponds to quality volumetric compensation and trading volumes.*

Oil and gas sales volumes for the three and nine months ended September 30, 2018, were lower than the comparable prior year periods primarily due to lower production in Colombia and higher inventory in Peru, resulting in lower volumes available for sale. During the third quarter of 2018, the Company sold more barrels than it produced in Colombia, resulting in an overlift liability position of 809 Mbbl at the end of the period. In Peru, the Company has experienced higher inventory during the year relating to unsold production from Block 192 due to the pipeline issues.

Colombia Royalties - PAP

The Company makes 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 as accumulated production has exceeded 5 MMbbl and escalates as oil prices increase above a minimum baseline WTI price. The increase in benchmark oil prices has triggered higher PAP obligations payable both in-kind (reducing the Company's net production) and in cash (increasing royalties).

The Company paid approximately 5.2% (combined cash and in-kind) of its production in the quarter as PAP, which was higher than 1.2% in the same period of 2017 and 4.4% in the previous quarter of 2018. For the nine months ended September 2018, the Company paid 4.3% from production as compared with 1.3% in the same period of 2017. The Company paid in-kind volumes averaging 2,625 bbl/d and 2,022 bbl/d during the third quarter and nine months ended September 2018, respectively, compared with no PAP in-kind volumes in both of the same prior year periods. In the second quarter of 2018, the Company paid 2,059 bbl/d as PAP in-kind volumes.

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 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 as royalties paid in-kind.

As of September 30, 2018, the Company has received in-kind payments for its services in the amount of 84% of the production from the block with the balance being retained by Perupetro. Perupetro retained in-kind volumes averaging 627 bbl/d and 1,138 bbl/d during the three and nine months ended September 30, 2018, respectively, compared with 1,093 bbl/d and 689 bbl/d in the same periods of 2017. In the second quarter of 2018, Perupetro retained in-kind volumes of 1,218 boe/d.

Overlift and 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 to recognize the gross margin earned on the related sale in the period of production.

Reference and Realized Price

					Nine months ended September 30	
		Q3 2018	**Q2 2018**	**Q3 2017**	**2018**	**2017**
Reference price						
Brent	($/bbl)	75.84	74.97	52.17	72.75	52.51
Average realized prices						
Realized oil price	($/bbl)	70.87	70.44	50.33	68.62	47.72
Realized natural gas price	($/boe)	24.71	23.10	21.26	23.65	21.45
Other revenue (1)	($/boe)	0.25	0.55	1.22	0.74	1.13
Net sales realized price						
Oil and gas sales and other revenue	($/boe)	68.02	67.82	47.55	66.03	47.12
Realized (loss) gain on risk management contracts	($/boe)	(10.02)	(11.12)	0.31	(10.13)	(0.44)
Royalties	($/boe)	(2.72)	(2.04)	(0.70)	(2.16)	(0.82)
Diluent cost	($/boe)	(1.89)	(1.74)	(1.21)	(1.83)	(1.17)
Net sales realized price	**($/boe)**	**53.39**	**52.92**	**45.95**	**51.91**	**44.69**

1. Includes revenue from infrastructure and other assets (including PEL until its disposal on April 19, 2018).

For the three and nine months ended September 30, 2018, net sales realized price increased by 16%, respectively, compared to the same periods of 2017. This was primarily driven by the increase in the Brent benchmark oil price (which is up 39% year-to-date compared to 2017) and better price differentials during 2018. Oil prices have risen as a result of stronger oil demand primarily from Asia, supply disruptions in Venezuela and lower Iran exports due to international sanctions.

In both 2018 periods, realized losses on risk management contracts offset the increases in oil prices as the Company had established hedging positions at lower prices in the prior year to provide downside protection following the restructuring in 2016. These risk management contracts expired on October 31, 2018, and the Company is unhedged with respect to oil prices through the end of 2018, allowing it to fully benefit from higher Brent benchmark oil prices.

Operating Netback

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

	Q3 2018		Q2 2018		Q3 2017	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	299,965	53.39	326,608	52.92	267,038	45.95
Production cost (2)	(85,182)	(15.81)	(82,450)	(14.13)	(70,940)	(10.85)
Transportation cost (2)	(74,210)	(13.77)	(68,935)	(11.81)	(76,931)	(11.77)
Operating netback (3)	**140,573**	**23.81**	**175,223**	**26.98**	**119,167**	**23.33**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes (D&P) (4)		61,071		67,822		63,162
Net production (5)		58,558		64,140		71,068

1. Per boe is calculated using sales volumes (D&P). Refer to the "Reference and Realized Price" and "Sales" sections on pages 7 and 9.
2. Per boe is calculated using net production after royalties.
3. Refer to the "Non-IFRS Measures" section on page 16 for details and a description of the operating netback calculation.
4. Sales volumes (D&P) excludes volumes from E&E assets as the related sales and costs are capitalized under IFRS.
5. Refer to the "Production" section on page 5.

Operating netback for the third quarter of 2018 increased by 2% to $23.81/boe from 23.33/boe in the same quarter of 2017, primarily due to the higher net sales realized price from the improvement in Brent oil benchmarks, partially offset by higher production costs from well services in Colombia, as well as higher workover and maintenance activities in Block 192 in Peru. On a per boe basis, both production and transportation costs have increased as a result of lower net production.

In comparison to the second quarter of 2018, operating netback was 12% lower due to workovers and maintenance in Block 192 in Peru. The variance in transportation costs was primarily due to the cost recovery of $5.2 million or $0.89/boe, from the Ocensa P-135 Settlement Agreement recognized in the second quarter of 2018. On a per boe basis, both production and transportation costs have increased as a result of lower net production.

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

	Nine months ended September 30			
	2018		2017	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	857,098	51.91	806,893	44.69
Production cost (2)	(241,954)	(14.08)	(197,857)	(10.07)
Transportation cost (2)	(218,723)	(12.73)	(261,618)	(13.31)
Operating netback (3)	**396,421**	**25.10**	**347,418**	**21.31**
		(boe/d)		**(boe/d)**
Sales volumes (D&P) (4)		60,476		66,147
Net production (5)		62,947		71,982

References 1 through 5 are consistent with those included in the quarterly Operating Netback table above.

Operating netback for the nine months ended September 30, 2018 increased by 18% to $25.10/boe from $21.31/boe in the same period of 2017, primarily due to the higher net sales realized price from the improvement in Brent oil benchmarks. The improvement in global benchmark oil prices was partially offset by an increase in royalties (which are correlated with the underlying oil price) and diluent costs. Additionally, the Company recognized lower transportation cost due to the increased use of the OCENSA pipeline during 2018 compared to higher cost transportation alternatives used in 2017. This reduction was partially offset by higher production costs from maintenance and well services in Colombia, and workovers and maintenance activities in Block 192 in Peru.

Sales

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Oil and gas sales and other revenue [1]	382,189	276,345	1,090,283	846,531
Realized (loss) gain on risk management contracts	(56,297)	1,792	(167,303)	(3,650)
Royalties	(15,280)	(4,047)	(35,629)	(14,842)
Diluent cost	(10,647)	(7,052)	(30,253)	(21,146)
Net sales [2]	**299,965**	**267,038**	**857,098**	**806,893**
$/boe using sales volumes	53.39	45.95	51.91	44.69

1. *"Oil and gas sales and other revenue" for previous quarters included in this MD&A 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. For further information on this change in presentation, refer to Note 2 of the Interim Financial Statements.*
2. *Beginning in the third quarter of 2018, the Company changed the composition of "Net sales" which had previously been referred to as "Total sales after realized (loss) gain on risk management contracts". Refer to the "Non-IFRS Measures" section on page 16 for more details.*

Net sales for the three and nine months ended September 30, 2018 increased by $32.9 million (12%) and $50.2 million (6%), respectively, compared to the same prior year periods. The following table describes the various factors that had an impact on the increase in net sales for both the three and nine months ended September 30, 2018:

	Three months ended September 30	Nine months ended September 30
($M; YTD analysis in parenthesis)	**2018 - 2017**	**2018 - 2017**
Net sales for the period ended September 30, 2017	267,038	806,893
Increase due to 43% higher oil and gas price (YTD - 40% higher)	115,011	312,201
Higher realized loss on risk management contracts	(58,089)	(163,653)
Increase in royalties	(11,233)	(20,787)
Decrease due to lower volumes sold of 2,091 boe/d or 3% (YTD - lower 5,671 boe/d or 9%)	(9,147)	(72,960)
Increase in diluent cost	(3,595)	(9,107)
Other revenue (decrease) increase	(20)	4,511
Net sales for the period ended September 30, 2018	**299,965**	**857,098**

Royalties

	Three months ended September 30		Nine months ended 30 September	
($M)	**2018**	**2017**	**2018**	**2017**
Cash royalties Colombia	14,990	3,747	34,931	12,692
Cash royalties Peru	290	300	698	2,150
Royalties [1]	**15,280**	**4,047**	**35,629**	**14,842**
$/boe using sales volumes	2.72	0.70	2.16	0.82

1. *Previously referred to as "High-price participation payments and cash royalties".*

Royalties for the three and nine months ended September 30, 2018 increased by $11.2 million and $20.8 million, respectively, as the Company's royalty burden is directly correlated with the increase in benchmark oil prices due to the price sensitivity of PAP in Colombia. Refer to the "Production" section for further details of royalties paid in-cash and in-kind.

Oil and gas operating costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Production cost	85,182	70,940	241,954	197,857
Transportation cost	74,210	76,931	218,723	261,618
Diluent cost	10,647	7,052	30,253	21,146
Inventory valuation	(13,038)	(17,527)	(20,999)	(21,463)
Overlift	37,212	106	42,732	81
Rubiales post-termination	—	4,358	—	4,358
Total oil and gas operating costs	**194,213**	**141,860**	**512,663**	**463,597**

Total oil and gas operating costs for the three and nine months ended September 30, 2018, increased by 37% and 11% to $194.2 million and $512.7 million from $141.9 million and $463.6 million, respectively, from the comparable periods in 2017. Total oil and gas operating costs changed mainly due to the following:

- Production cost increased by 20% and 22% in the three and nine months ended September 30, 2018, respectively, compared with the same periods of 2017, mainly as a result of higher production costs from well services in Colombia, and workovers and maintenance activities in Block 192 in Peru.
- Transportation cost decreased by 4% and 16% in the three and nine months ended September 30, 2018, respectively, compared with the same periods of 2017, due to the lower Ocensa tariff from the P-135 Settlement Agreement and less expensive transportation alternatives used in 2018.
- Diluent cost increased by 51% and 43% in the three and nine months ended September 30, 2018, respectively, compared with the same periods of 2017, mainly due to a change in the dilution program resulting from the termination of the transportation contracts with Bicentenario and CENIT.
- Overlift for the three and nine months ended September 30, 2018 was higher due to an overlift balance at September 30, 2018 of 809 Mbbl, compared with an overlift balance of 1 Mbbl as of September 30, 2017.

Other selected operating costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Fees paid on suspended pipeline capacity	5,633	34,838	82,372	84,175
Payments under terminated pipeline contracts	15,578	—	15,578	—
Reversal of provision related to high-price clause	(21,832)	—	(21,832)	—

Fees paid on suspended pipeline capacity decreased due to the termination of the transportation contracts with Bicentenario and CENIT on July 13, 2018. Payments under terminated pipeline contracts represent the net amounts paid to Bicentenario post-termination of the BIC pipeline contracts.

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

For further information of other selected operating costs, refer to the "Commitments" section on page 20.

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
General and administrative	22,962	26,569	71,183	80,373
$/boe using net production	4.26	4.06	4.14	4.09

General and administrative expenses ("**G&A**") for the three months ended September 30, 2018, decreased in comparison with the previous period. For the nine months ended September 30, 2018, G&A decreased by 11% to $71.2 million compared with the same period of 2017. Lower G&A in both periods primarily reflects a reduction in employee-related expenses and the Company's continued efforts to reduce overhead costs. On a per boe basis, G&A increased as a result of lower net production in both periods. Refer also to the "Restructuring, Severance and Other Costs" section on page 12.

Depletion, Depreciation and Amortization

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Depletion, depreciation and amortization	78,041	87,802	236,290	287,184

Depletion, depreciation and amortization expense ("**DD&A**") decreased by 11% and 18% for the three and nine months ended September 30, 2018, respectively, compared to the same prior year periods. The decrease for both periods is primarily due to lower production volumes and a lower depletable base resulting from property divestments and impairment charges.

Impairment and Exploration Expenses

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Impairment of investment in associates	23,296	—	142,172	—
Impairment of assets held for sale - transmission line assets	—	18,000	9,125	41,159
Impairment of properties plant and equipment	4,786	56,000	4,786	56,000
Impairment (reversal) of exploration and evaluation assets	24,735	—	26,742	(11,625)
Impairment of other assets - VAT receivable	4,287	—	4,556	1,178
Other	1,188	—	1,188	—
Total impairment	**58,292**	**74,000**	**188,569**	**86,712**
Exploration expenses	779	—	779	—
Total impairment and exploration expenses	**59,071**	**74,000**	**189,348**	**86,712**

During the third quarter of 2018, total impairment and exploration expenses were $59.1 million, primarily relating to the following charges:

- $23.3 million on the investment in Bicentenario arising from the exercise of the PML Bicentenario Put Option for the gross purchase price of $84.8 million. The Company identified this new event as an impairment indicator, and updated its impairment test for a higher risk associated with the timing and receipt of dividends from Bicentenario. In the previous quarter, the Company recognized an impairment charge of $107.7 million on the same investment after the termination of its transportation contract with Bicentenario. That impairment was primarily driven by reduced volumes, revenues and cash flows associated with the terminated ship-or-pay commitments on the BIC pipeline.
- $26.6 million in Peru as result of exploratory drilling work on the Delfin-Sur 1 well, which did not justify further evaluation. As a result, the well was abandoned and the impairment charge was calculated based on the recoverable amount of the related Peru off-shore cash-generating unit ("**CGU**").
- $4.6 million relating to the water treatment facilities of Agro Cascada S.A.S. The facilities, which had been valued based on a third party purchase offer, were written down upon the subsequent cancellation of that offer.

During the third quarter of 2017, the Company recognized total impairment and exploration expenses of $74.0 million, of which $56.0 million was recognized with respect to natural gas assets located in the Colombia North CGU. The carrying value of the assets was written down to a recoverable amount consistent with a purchase offer received at the time. In addition, the Company recognized an impairment charge of $18.0 million with respect to the divestment of its transmission line assets. The carrying value of the assets was ultimately written down to a recoverable amount consistent with the final purchase offer.

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

Restructuring, Severance and Other Costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Restructuring and other costs	1,505	1,942	2,787	2,673
Severance	603	451	3,713	7,508
Total restructuring, severance and other costs	**2,108**	**2,393**	**6,500**	**10,181**

Restructuring, severance and other costs for the three and nine months ended September 30, 2018, were $2.1 million and $6.5 million, a decrease of 12% and 36% from the comparable periods in 2017, respectively. This decrease was primarily the result of higher expenses recognized during 2017 following the completion of the Company's restructuring transaction in November 2016.

During the third quarter of 2018, the Company pursued actions aimed at delivering improvements in areas relating to controls, compliance and operational efficiencies. Subsequent to the third quarter, the Company implemented an organizational restructuring plan, which includes various cost reduction initiatives targeting both operating and capital efficiencies.

Non-Operating Costs

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Finance costs, net	(6,059)	(7,207)	(19,805)	(18,690)
Share of income from associates	19,239	27,452	74,649	61,377
Foreign exchange (loss) gain	(1,094)	6,511	9,712	5,348

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 third quarter of 2018 were $6.1 million, or 16% lower than the comparable quarter of 2017, primarily due to the higher interest income earned on cash balances. For the nine months ended September 30, 2018, total finance costs were $19.8 million, 6% higher compared to the same period of 2017 as a result of higher accretion expense from receivables and transaction fees relating to the closing of both the Unsecured Notes and Unsecured LC Facility in 2018 (as defined herein).

Share of Income from Associates

The Company's share of income from associates for the third quarter of 2018 was $19.2 million, 30% lower than the comparable quarter of 2017 primarily due to the termination of the transportation contracts with Bicentenario, which resulted in lower income for the related associate investees. For the nine months ended September 30, 2018, the share of income from associates was 22% higher than the same prior year period primarily due to the Colombian peso ("**COP**") functional currency of certain associates, which depreciated by 1% relative to the U.S. dollar ("**USD**").

Foreign Exchange (Loss) Gain

The Company recognized a foreign exchange loss of $1.1 million in the third quarter of 2018 compared to a gain of $6.5 million in the same quarter of 2017. Fluctuations in foreign exchange balances are primarily due to the impact of the COP's appreciation against the USD on the translation of the Company's net working capital balances.

Gain (Loss) on Risk Management Contracts

($M)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Realized (loss) gain on risk management contracts	(56,297)	1,792	(167,303)	(3,650)
Unrealized gain (loss) on risk management contracts	61,830	(43,567)	75,945	9,012
Total gain (loss) on risk management contracts	**5,533**	**(41,775)**	**(91,358)**	**5,362**

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. As at September 30, 2018, the Company has hedges in place for 1.8 MMbbl expiring in October 2018, and 1.9 MMbbl of put options expiring between January 2019 and September 2019. The objective for 2019 is to continue hedging, where effective, to provide a base level of cash flow that assures that the Company can execute a substantial 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, call spreads and put options instruments. As at September 30, 2018, the Company had outstanding hedge positions for a total of 3.7 MMbbl with average floor and ceiling strike Brent prices of $55.50/bbl and $61.21/bbl, respectively, with a net liability representing a fair value of $27.6 million.

Type of Instrument	Term	Benchmark	Notional Amount / Volume (bbl)	Strike Prices Put /Call; Call Spreads	Carrying Amount ($M) Assets	Carrying Amount ($M) Liabilities
Zero-cost collars	October 2018	Brent	1,200,000	52.00 / 64.75	—	(25,380)
Call spreads	October 2018	Brent	600,000	59.00 / 63.88	—	(2,733)
Put options	January 2019 to September 2019	Brent	1,890,000	55.00	502	—
As at September 30, 2018					502	(28,113)
Zero-cost collars	January 2018 to October 2018	Brent	12,000,000	49.11 / 61.63	—	(102,104)
Call spreads	October 2018	Brent	600,000	59.00 / 63.88	—	(1,643)
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 September 30, 2018, the Company had outstanding foreign currency forward contracts for the months of October to December 2018, for a total notional amount of $79.5 million, with a fair value of $0.9 million.

Type of Instrument	Term	Benchmark	Notional Amount ($M)	Put/ Call; Par forward (COP$)	Carrying Amount ($M) Assets	Carrying Amount ($M) Liabilities
Zero-cost collars	October 2018 to December 2018	COP$ / U.S.$	15,000	3,000 / 3,007	141	—
Forward	October 2018 to December 2018	COP$ / U.S.$	64,500	3,010	769	—
As at September 30, 2018					910	—
As at December 31, 2017					—	—

Income Tax Expense

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Current income tax expense	(8,787)	(12,134)	(24,570)	(25,703)
Deferred income tax recovery	28,604	—	21,916	—
Total income tax recovery (expense)	**19,817**	**(12,134)**	**(2,654)**	**(25,703)**

The current income tax expense for the third quarter of 2018 was $8.8 million. The current income tax expense year to date is $24.6 million, which includes minimum income taxes (presumptive tax) of $20.0 million, a tax of $3.5 million coming from the dividends of the investments in associates, and current taxes in countries other than Colombia of $1.1 million. In addition, during the nine months ended September 30, 2018, the Company recognized an income tax expense of $15.9 million related to the utilization of the deferred tax asset, offset by an income tax recovery of $37.8 million related to the recognition of a deferred tax asset.

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

Net Income (Loss)

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Net income (loss) attributable to equity holders of the Company	45,105	(141,115)	(142,452)	(184,159)
Per share ($) - basic and diluted	0.45	(1.41)	(1.42)	(1.84)

The Company reported net income of $45.1 million in the third quarter of 2018, compared to a net loss of $141.1 million in the same quarter of 2017. The change was primarily the result of an increase in cash from operating activities driven by higher net sales, a decrease in combined losses from risk management contracts as most of the Company's hedges settled during 2018, the reversal of a PAP provision of $21.8 million, and a deferred tax recovery of $28.6 million on the recognition of a deferred tax asset in the third quarter.

In the nine month period ended September 30, 2018, the Company reported a net loss of $142.5 million compared to $184.2 million in the same period in 2017. This was primarily due to higher net sales in excess of operating costs and lower DD&A expense of $50.9 million, partially offset by higher impairment charges of $102.6 million and higher realized loss on risk management contracts as a result of the settlements during 2018. The results for 2018 also included a non-cash loss of $50.8 million resulting from currency translation adjustments on the deconsolidation of PEL following its sale and a $25.6 million loss on the extinguishment of debt from the Company's refinancing in the second quarter of 2018.

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Maintenance and development drilling	65,744	33,950	148,877	99,868
Exploration activities [1]	31,716	7,602	84,212	9,786
Facilities and infrastructure	26,528	4,342	50,040	9,598
Administrative assets and other projects	41	2,669	6,554	5,936
Total capital expenditures	**124,029**	**48,563**	**289,683**	**125,188**

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

Capital expenditures for the three and nine months ended September 30, 2018, were $124.0 million and $289.7 million, a 155% and 131% increase from $48.6 million and $125.2 million in the same periods of 2017, respectively. The Company continues to execute on its active exploration and development drilling program with eight rigs in operation during the second quarter and an average of 10 rigs in the third 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 94 development wells were drilled during the nine months ended September 2018 compared to 58 in the same prior year period, including new horizontal oil wells in Quifa during the second and third quarters.

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. The first stage of the water handling expansion project started at the end of October with full implementation expected by the end of the year. During the third quarter of 2018, the Company drilled and completed 37 development wells compared with 24 development wells during the third quarter of 2017, and 23 development wells during second quarter of 2018.

Selected Quarterly Information

		2018			2017				2016
Operational and Financial Results		**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Oil production	(bbl/d)	54,436	59,636	61,352	59,131	65,641	66,448	66,035	62,229
Natural gas production	(boe/d)	4,122	4,504	4,875	5,314	5,427	5,922	6,489	7,203
Net production [1]	(boe/d) [2]	58,558	64,140	66,227	64,445	71,068	72,370	72,524	69,432
Sales volumes	(boe/d)	61,071	67,822	52,440	65,481	63,162	64,908	70,452	67,470
Brent price	($/bbl)	75.84	74.97	67.23	61.46	52.17	50.79	54.57	51.06
Oil and gas sales and other revenue	($/boe)	68.02	67.82	61.34	56.19	47.55	45.71	47.34	43.44
Realized (loss) gain on risk management contracts	($/boe)	(10.02)	(11.12)	(8.98)	(2.93)	0.31	0.57	(1.39)	(1.52)
Royalties	($/boe)	(2.72)	(2.04)	(1.64)	(1.21)	(0.70)	(0.83)	(0.93)	(0.95)
Diluent cost	($/boe)	(1.89)	(1.74)	(1.88)	(1.00)	(1.21)	(1.22)	(1.08)	(0.53)
Net sales realized price	($/boe)	53.39	52.92	48.84	51.05	45.95	44.23	43.94	40.44
Production cost	($/boe)	(15.81)	(14.13)	(12.47)	(13.13)	(10.85)	(9.93)	(9.43)	(11.45)
Transportation cost	($/boe)	(13.77)	(11.81)	(12.68)	(14.28)	(11.77)	(14.19)	(13.98)	(14.52)
Operating netback [3]	($/boe)	23.81	26.98	23.69	23.64	23.33	20.11	20.53	14.47
Net income (loss) [4]	($M)	45,105	(184,436)	(3,121)	(32,544)	(141,115)	(51,542)	8,498	4,025,194
Per share – basic and diluted [5]	$	0.45	(1.84)	(0.03)	(0.33)	(1.41)	(0.52)	0.08	40.25
General and administrative	($M)	22,962	26,168	22,053	24,450	26,569	26,098	27,706	39,640
Operating EBITDA [3]	($M)	93,455	124,667	85,988	105,010	105,885	86,857	92,442	44,275
Capital expenditures [6]	($M)	124,029	86,813	78,841	111,213	48,563	37,826	38,799	64,707

1. Net production represents the Company’s working interest volumes, after 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 16.
4. Net income (loss) attributable to equity holders of the Company.
5. The basic and diluted weighted average number of Common Shares are stated on an adjusted post split-split basis.
6. Capital expenditures includes sales from E&E assets.

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 have resulted from natural declines on existing fields and suspension of operations due to unforeseen circumstances, such as community blockades. The Company has had fluctuating production in Peru as operations at Block 192, which had ramped up during the second half of 2017, have since then experienced periods of suspension under force majeure due to community and pipeline issues. 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, gas and other 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 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.

Changes in Presentation of Non-IFRS Measures

Beginning with this MD&A for the third quarter of 2018, the Company changed the composition and terminology of certain non-IFRS measures and eliminated other metrics that are no longer considered in its assessment of operational and financial performance. These changes resulted from a comprehensive review of key performance disclosures to improve the clarity and comparability of the Company’s financial and operational results amongst its industry peer group in Canada and Latin America. As a result of this review, the following changes have been incorporated in this MD&A:

- Operating netback:
    - Royalties and diluent cost have been reclassified from operating costs to net sales realized price. Royalties (previously referred to as “PAP and cash royalties”) was reclassified as the Company now reports revenue net of royalties in the Interim Financial Statements. The cost of diluent is recognized within net sales realized price in order to offset the incremental impact on sales as this cost is partially recovered when the blended product is sold.
- Net sales was previously referred to as “total sales after realized (loss) gain on risk management contracts”. In addition, the Company changed the calculation of this measure to also deduct royalties and diluent cost for the same reasons described above. For netback purposes, the Company removes all the effects of trading activities from its per barrel metrics.

The following have been eliminated as non-IFRS measures and will no longer be reported by the Company:

- “Adjusted EBITDA” and “adjusted netback” were removed as non-IFRS measures, as the Company no longer incurs fees for suspended pipeline capacity, which represented the most significant adjustment from operating EBITDA. As a result, the Company believes that one measure of EBITDA and netback is more useful for management, analysts, investors and other stakeholders to evaluate its operating performance.
- “Adjusted funds flow from operations (“**FFO**”)” and “adjusted FFO netback” were removed as non-IFRS measures, as the Company believes that cash provided by operating activities, which is defined in IFRS, represents a more commonly used and better understood measure of the Company’s ability to generate cash from its operations.

All non-IFRS measures reported for previous quarters and included in this MD&A have been recalculated and presented using the approach described above.

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 September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Net income (loss) [1]	**45,105**	**(141,115)**	**(142,452)**	**(184,159)**
Adjustments				
Reversal of provision related to high-price clause	(21,832)	—	(21,832)	—
Fees paid on suspended pipeline capacity	5,633	34,838	82,372	84,175
Payments under terminated pipeline contracts	15,578	—	15,578	—
Share-based compensation	1,042	233	3,876	486
Depletion, depreciation and amortization	78,041	87,802	236,290	287,184
Impairment and exploration expenses	59,071	74,000	189,348	86,712
Restructuring, severance and other costs	2,108	2,393	6,500	10,181
Share of income from associates	(19,239)	(27,452)	(74,649)	(61,377)
Equity tax	—	—	—	11,694
Foreign exchange loss (gain)	1,094	(6,511)	(9,712)	(5,348)
Finance costs, net	6,059	7,207	19,805	18,690
Unrealized (gain) loss on risk management contracts	(61,830)	43,567	(75,945)	(9,012)
Other loss, net	2,606	8,487	3,909	639
Reclassification of currency translation adjustments	—	—	50,847	—
Loss on extinguishment of debt	—	—	25,628	—
Income tax (recovery) expense	(19,817)	12,134	2,654	25,703
Non-controlling interests	(164)	10,302	(8,107)	19,616
Operating EBITDA	**93,455**	**105,885**	**304,110**	**285,184**

1. Net income (loss) attributable to equity holders of the Company.

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 9.

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 "Operating Netback" section on page 8.

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 (D&P). A reconciliation of this calculation is provided below:

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Net sales	299,965	267,038	857,098	806,893
Denominator (boe)				
Sales volumes (D&P)	5,618,537	5,810,904	16,509,850	18,058,228
$/boe net sales realized price	53.39	45.95	51.91	44.69

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

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Production cost	(85,182)	(70,940)	(241,954)	(197,857)
Denominator (boe)				
Net production	5,387,305	6,538,210	17,184,464	19,650,959
$/boe production cost	(15.81)	(10.85)	(14.08)	(10.07)

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

	Three months ended September 30		Nine months ended September 30	
($M)	**2018**	**2017**	**2018**	**2017**
Transportation cost	(74,210)	(76,931)	(218,723)	(261,618)
Denominator (boe)				
Net production	5,387,305	6,538,210	17,184,464	19,650,959
$/boe transportation cost	(13.77)	(11.77)	(12.73)	(13.31)

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; 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, cash flows from operations, and available debt and credit facilities. In accordance with the Company's investment policy, available cash balances are held in interest-bearing savings accounts, term deposits and Colombian mutual funds with high credit ratings and liquidity.

As at September 30, 2018, the Company had total cash balances of $786.5 million (including restricted cash), an increase of $186.6 million as compared to December 31, 2017. This increase was primarily due to $328.0 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 $32.6 million from financing activities primarily due to the issuance of $350.0 million senior unsecured notes at a coupon rate of 9.7%, maturing in 2023 (the "**Unsecured Notes**") in the second quarter of 2018, which resulted in net cash proceeds of $60.0 million after transaction costs and the repurchase of $250.0 million 10% senior secured notes (the "**Secured Notes**"). These factors were partially offset by net capital expenditures of $289.7 million in the first nine months of 2018 as the Company continued to expand development and production facilities across its core assets.

Total cash balances include short-and long-term restricted cash of $199.9 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, cash collaterals required in certain legal processes, and proceeds from the sale of PEL held in escrow. Abandonment funds are expected to be released in the long-term as assets are required to be abandoned. Cash collaterals for legal processes are expected to be released as the processes are closed. Finally, the PEL proceeds held in escrow of $50.0 million were released on October 19, 2018.

As at September 30, 2018, the Company had a working capital surplus of $331.2 million, an increase of $21.2 million as compared to December 31, 2017. Working capital balances in conjunction with future cash 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 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 Secured Notes, which were set to mature in 2021. The remaining proceeds were used for general corporate purposes. 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 letter of credit facility (the "**Secured LC Facility**") with a $100.0 million unsecured letter of credit facility (the "**Unsecured LC Facility**") with a maturity date of May 17, 2020. As at September 30, 2018, the outstanding letters of credit issued and maintained under the Unsecured LC Facility for exploration and operational commitments totalled $89.1 million. The lenders receive an amount equal to 3.0% per annum on any undrawn issued and outstanding amounts of the letters of credit, due and payable in arrears on the last business day of each calendar month. If any amounts are drawn under the Unsecured LC Facility, interest accrues at 6% per annum. If any event of default exists, the applicable rate will increase by an additional 2% per annum until such default is cured.

Under the Unsecured LC Facility, the Company issued $64.4 million of standby letters of credit ("**SBLCs**") as a guarantee relating to the transportation contract with Bicentenario. During the third quarter, Bicentenario had drawn $5.3 million under the issued SBLCs. Subsequently, Bicentenario drew the remaining amount under the SBLCs of $59.1 million. Under the terms of the Unsecured LC Facility, the Company must reimburse the executed amounts to the issuing bank within two business days, which the Company has done.

Covenants

The Unsecured Notes are senior, unsecured and rank equal in right of payment with all of the existing and future senior unsecured debt and are guaranteed by the Company's principal subsidiaries. Under the terms of both the Unsecured Notes and the Unsecured LC Facility, the Company may, 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. As at September 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 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.*

Guarantees

The Company has various guarantees in place in the normal course of business. As at September 30, 2018, in addition to letters of credit issued from the Unsecured LC Facility of $89.1 million, the Company also issued $3.7 million of cash collateralized letters of credit. At September 30, 2018, guarantees for exploration and operational commitments totalled $92.8 million.

Commitments

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

($M)	2018	2019	2020	2021	2022	2023 and Beyond	Total
Financial							
Debt	—	—	—	—	—	350,000	350,000
Finance lease	1,143	4,943	5,724	4,279	—	—	16,089
Transportation commitments							
Oleoducto de los Llanos Orientales Ship-or-Pay Agreement	12,549	50,197	30,831	1,151	—	—	94,728
Bicentenario Ship-or-Pay Agreements (1)	2,047	8,189	8,189	8,189	8,189	14,498	49,301
Ocensa P-135 Ship-or-Pay Agreement	16,822	67,287	67,287	67,287	67,287	168,548	454,518
Pacific Infrastructure Ventures Inc. Take-or-Pay Agreements	9,571	41,653	41,653	41,768	—	—	134,645
Transportation and processing commitments	12,910	49,334	48,791	48,791	48,720	185,473	394,019
Exploration commitments							
Minimum work commitments	77,299	39,109	55,510	27,546	—	—	199,464
Other commitments							
Operating purchases and leases	58,873	21,549	18,377	17,519	10,769	8,063	135,150
Community obligations	4,305	1,471	—	—	—	—	5,776
Total	**195,519**	**283,732**	**276,362**	**216,530**	**134,965**	**726,582**	**1,833,690**

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

Ocensa P-135 Project Arbitration Settlement

On July 12, 2018, the Company and Ocensa reached the P-135 Settlement Agreement in an arbitration on tariffs and monetary conditions relating to transportation contracts entered into with Ocensa concerning the P-135 Project. 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), and $6.91 per barrel under a temporary payment agreement that was in effect during the arbitration process. During the second quarter of 2018, the Company recognized a recovery of $5.2 million in transportation costs related to the difference between the rates under this temporary payment agreement and the P-135 Settlement Agreement (2017: $ Nil).

As a result of the P-135 Settlement Agreement, total commitments for the Ocensa P-135 Project of $648.3 million (as at June 30, 2018) were reduced to $470.0 million to reflect the settlement tariff terms.

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

Termination of Transportation Agreements

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. On the date of termination, commitments under contracts totalled $1.35 billion and were excluded from the commitments table above.

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

The Company continues to have existing take-or-pay contracts for storage and offloading facilities in Araguaney, Banadia and Coveñas, for $49.3 million and $154.3 million with Bicentenario and CENIT, respectively. The Company also has take-or-pay commitments for the Monterey-Araguaney pipeline, which connects the Oleoducto de los Llanos Orientales S.A. (“**ODL**”) and BIC pipelines, totalling $114.3 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 contracts, which the Company vigorously rejects. As at September 30, 2018, a total of $33.4 million in payments were not made since the termination of these contracts.

Payments Under Terminated Pipeline Contracts

For the three and nine months ended September 30, 2018, the net amounts paid to Bicentenario post termination of the BIC pipeline contracts, totalled $15.6 million. The amount comprises $5.3 million drawn under the SBLCs, $6.8 million of advance payment for services in July related to the period after the termination date of July 12, 2018, and $3.5 million in credit notes receivable for June 2018 activity.

During the third quarter of 2018, Bicentenario had drawn $5.3 million under the SBLCs issued to guarantee obligations under the terminated BIC pipeline contract. These SBLCs are autonomous and irrevocable, and thus did not automatically terminate upon early termination of the BIC pipeline contract. The Company intends to pursue the recovery of the amounts drawn under the issued SBLCs and payments made in advance for services in July for the period after the termination date of July 12, 2018.

On October 23, 2018, the Company provided notice that it intends not to renew the SBLCs, which expire in November 2018. Subsequent to September 30, 2018, the remaining issued and outstanding SBLCs of $59.1 million were drawn by Bicentenario and will be recognized as Payments under Terminated Pipeline Contracts expense in the fourth quarter of 2018.

The Company intends to pursue the recovery of the amounts drawn under the issued SBLCs and the other payments described above.

Suspended Pipeline Capacity Fees

For the three and nine months ended September 30, 2018, the net fees paid relating to the periods of disrupted/suspended pipeline capacity were $5.6 million and $82.4 million, respectively (2017: $34.8 million and $84.2 million, respectively).

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 - refer to 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 to 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).

Subsequent to September 30, 2018, new deficiency notices were received that require Pacinfra and PIV to fund an additional $11.1 million in December 2018.

Reversal of PAP Provision

Upon acquisition of certain exploration and production contracts via business combination transactions in prior years, in accordance with IFRS 3 Business Combinations, a contingent liability provision was recognized with respect to disagreements with the ANH on interpretations of the PAP for each designated exploitation area within a block under contract.

As at December 31, 2017, the Company reversed $99.6 million in contingent liability provisions related to the Corcel Block upon receipt of a ruling from an arbitration panel in favour of the Company's position. In 2018, the Company commenced a process to review other contingent liability provisions previously recognized, and reversed a further $21.8 million for an additional block in the third quarter of 2018. The provision was reversed during the third quarter as an external legal opinion supported the Company's technical interpretation that the clause would not apply to a certain designated exploitation area within one of its blocks.

The Company continues to not disclose the provision amounts recognized as required by IFRS, as this would be prejudicial to the outcome of potential disputes with the ANH.

Additional information on the Company's disagreements with the ANH is included in "Note 24 - Commitments and Contingencies" of the 2017 Annual Financial Statements.

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 November 7, 2018:

	Number
Common Shares (1)	99,538,103
Deferred Share Units ("**DSUs**") (2)	143,007
Restricted Share Units ("**RSUs**") (3)	1,147,094

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 of the Board, in Common Shares, cash or a combination thereof. Only directors are entitled to receive DSUs.*
3. *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 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 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.*

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 normal course issuer bid ("**NCIB**"). The amount eligible for purchase under the NCIB represented approximately 3.5% of the Company's issued and outstanding Common Shares at the time of the NCIB. For the nine month period ending September 30, 2018, the Company has purchased for cancellation 307,912 Common Shares at a total cost of $4.5 million.

6. RELATED PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances outstanding (before impairment) and commitments with related parties, as at September 30, 2018 and December 31, 2017, and for the three and nine months ended September 30, 2018 and 2017:

($M)		Accounts Receivable & Deposits	Accounts Payable	Commitments(1)	Cash Advance(2)	Loans/ Debentures Receivable(2)	Interest Receivable(2)
ODL (3)	2018	22,437	693	94,728	—	—	—
	2017	421	231	130,303	—	—	—
Bicentenario	2018	1,126	—	49,301	87,278	—	—
	2017	12,660	469	902,375	87,278	—	—
PIV	2018	8,511	903	134,644	17,741	103,230	34,000
	2017	5,926	1,598	158,179	17,741	76,552	26,331
Interamerican	2018	145	—	—	—	2,224	613
	2017	145	72	—	—	2,224	362
CGX Energy Inc.	2018	848	—	—	—	23,087	2,206
	2017	120	—	—	—	16,122	1,516

		Three months ended September 30			Nine months ended September 30		
($M)		Sales	Purchases / Services	Interest Income(2)	Sales	Purchases / Services	Interest Income(2)
ODL	2018	—	12,572	—	1,359	34,118	0
	2017	995	12,035	—	2,995	36,384	0
Bicentenario	2018	—	5,344	—	—	58,142	0
	2017	—	30,549	—	—	98,212	0
PIV	2018	—	7,946	3,187	—	20,750	7,670
	2017	—	6,980	2,094	—	21,082	6,144
Interamerican	2018	—	—	84	3	2	251
	2017	—	2	84	333	23	251
CGX Energy Inc.	2018	149	—	247	458	—	690
	2017	—	—	177	—	—	508

1. *Excludes commitments related to terminated transportation agreements (refer to Commitments section on page 20).*
2. *Amounts presented based on contractual payment obligations, prior to impairments.*
3. *Accounts receivable balances for ODL include $22.1 million of dividends receivable.*

For details about significant changes to related party transactions, refer to the “Commitments” section on page 20.

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