FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

March 27, 2018
For the year ended December 31, 2017

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 Energy Corporation's ("**Frontera**" or the "**Company**") 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.

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent that they involve oil and gas that will be encountered only if the property in question is developed. The estimated values disclosed in this MD&A do not represent fair market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates for all properties due to the effects of aggregation. Disclosed well test results may be preliminary until analyzed or interpreted and are not necessarily indicative of long-term performance or ultimate recovery.

*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 audited Consolidated Financial Statements and related notes for the year ended December 31, 2017 and 2016 ("**Consolidated 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 20.*

*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, have been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com and on the Company's website at www.fronteraenergy.ca Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

1. MESSAGE TO THE SHAREHOLDERS

"Value over volumes" was Frontera's theme for 2017. Through a comprehensive review of the Company's producing assets, the new management team is applying best oil field practices to mitigate decline rates, identify new exploration and development drilling opportunities and improve production and reservoir performance. Operational and financial discipline further helped the Company deliver exceptional financial results despite several operational challenges in both Colombia and Peru. Operating EBITDA came in 20% higher than the midpoint of our upwardly revised guidance, while capital expenditures were 5% below the low end of the Company's downwardly revised guidance.

Net production after royalties and internal consumption was 70,082 boe/d in 2017, just below our exit production rate of 71,015 boe/d, and within our exit guidance range of 70,000 to 75,000 boe/d. The Company replaced 105% of produced 2P reserves; however, technical revisions related to legacy reservoir interpretation and well performance resulted in a decrease of 10% to overall 2P reserves. Despite the decrease in barrels, the Company was able to increase the before tax net present value discounted by 10% of 2P reserves by 9%, as a result of operational efficiencies, to $2.5 billion, despite a 4% decrease in the forward oil price assumptions used by external reserves auditors.

Initial results from our exploration and development drilling activities so far in 2018 have delivered encouraging results on the Quifa and Guatiquia blocks. These results, combined with the implementation of a waterflood project at Cubiro block during 2018, should position the Company for overall 2P reserves growth in 2018.

During 2017, Frontera consolidated all operations in Colombia into one branch: Frontera Energy Colombia Corp. (Colombian Branch) (formerly Meta Petroleum Corp. Colombian Branch). The purpose of this corporate reorganization was to simplify and streamline operational processes.

The balance sheet remains strong with $644.1 million of total cash, cash equivalents and restricted cash, offset by $250.0 million of long-term debt. In addition to the strong cash balance, the Company recently collected $57.0 million in cash proceeds by exercising its withdrawal right related to a working interest in Papua New Guinea. Frontera also enjoys a strong oil hedge book with over 50% of total Company production hedged at floor prices ranging from $50.77/bbl to $53.42/bbl and ceiling prices between $55.73/bbl and $61.63/bbl between April and October.

Frontera's theme for 2018 is "positioning for growth." The Company continues to pursue key contract renegotiations to restructure long-term take-or-pay obligations in Colombia and will look to work with Petroperu for a long-term contract extension on Block 192 in Peru. The Company is also excited about the Acorazado-1 exploration well on Block LLA-25 in the Llanos basin in Colombia. Such a deep and mechanically complex well requires the best people and equipment to mitigate the execution risk of the well. The Company has contracted the premium 3,000 horsepower rig in Colombia, the H&P-900, and brought in Exceed Well Management based in Aberdeen. Exceed have provided a highly experienced drilling team consisting of senior management and engineering staff, most of whom previously worked with major operators in Colombia and who have drilled dozens of successful wells in the Cusiana and Cupiagua complex.

Using an expected oil price of $63.00/bbl Brent and a realized oil price differential of $5.00/bbl to $5.50/bbl, the Company expects to deliver average annual 2018 net production after royalties of between 65,000 boe/d to 70,000 boe/d, which includes the impact of increased high price royalty barrels at Quifa and downtime experienced year to date at Cubiro as a result of social issues. These estimates are expected to deliver Operating EBITDA of between $375 and $425 million. Our capital expenditures program is targeting $450 to $500 million, of which half is expected to maintain production and reserves, and half will be invested in exploration and infrastructure projects that are anticipated to deliver reserves growth in 2018 and production growth in 2019.

Barry Larson
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operating Summary

		Q4 2017	Q3 2017	Q4 2016	Year Ended December 31 2017	Year Ended December 31 2016
Financial results						
Total sales	($M)	335,346	307,080	269,772	1,258,516	1,411,711
Oil and gas sales and other income	($M)	320,868	278,137	260,179	1,163,749	1,399,120
Trading sales	($M)	14,478	28,943	9,593	94,767	12,591
Net (loss) income (1)	($M)	(32,544)	(141,115)	4,025,194	(216,703)	2,448,523
Per share – basic (2)	$	(0.65)	(2.82)	80.50	(4.33)	48.97
Per share – diluted (2)	$	(0.65)	(2.82)	80.47	(4.33)	48.95
General and administrative costs	($M)	24,450	26,569	39,640	104,823	144,538
Operating EBITDA (3)	($M)	105,010	105,885	44,275	390,194	444,637
Operating EBITDA margin (Operating EBITDA/revenues)	%	31%	34%	16%	31%	31%
Adjusted EBITDA (3)	($M)	1,999	44,203	(1,967)	248,649	253,619
Adjusted EBITDA margin (Adjusted EBITDA/revenues)	%	1%	14%	(1)%	20%	18%
Adjusted FFO (4)	($M)	94,695	47,889	8,256	267,495	256,972
Per share – basic (2)	$	1.89	0.96	0.17	5.35	5.14
Per share – diluted (2)	$	1.89	0.96	0.17	5.35	5.14
Total assets	($M)	2,579,651	2,546,631	2,741,719	2,579,651	2,741,719
Total cash	($M)	644,086	599,891	502,881	644,086	502,881
Cash and cash equivalents – unrestricted	($M)	511,685	500,643	389,099	511,685	389,099
Restricted cash short-and long-term	($M)	132,401	99,248	113,782	132,401	113,782
Total equity	($M)	1,396,381	1,442,431	1,601,035	1,396,381	1,601,035
Debt and obligations under finance lease	($M)	269,229	270,222	272,942	269,229	272,942
Operational Results						
Net production after royalties (5,6)	(boe/d)	64,445	71,068	69,432	70,082	103,532
Oil production	(bbl/d)	59,131	65,641	62,229	64,298	94,769
Natural gas production	(mcf/d)	30,290	30,934	41,057	32,969	49,949
Combined price (including oil price risk management activities losses/gains)	($/boe)	53.26	47.86	41.92	48.32	40.36
Realized oil and gas price	($/boe)	56.19	47.55	43.44	49.20	35.97
Realized oil price risk management activities (loss) gain	($/boe)	(2.93)	0.31	(1.52)	(0.88)	4.39
Operating cost	($/boe)	(29.65)	(24.32)	(27.40)	(26.25)	(22.47)
Production cost	($/boe)	(13.13)	(10.85)	(11.45)	(10.78)	(8.27)
PAP and royalties paid in cash	($/boe)	(1.23)	(0.62)	(0.92)	(0.87)	(0.59)
Transportation (trucking and pipeline)	($/boe)	(14.28)	(11.77)	(14.52)	(13.54)	(12.16)
Diluent cost	($/boe)	(1.01)	(1.08)	(0.51)	(1.06)	(1.45)
Operating Netback (3)	($/boe)	23.61	23.54	14.52	22.07	17.89
Adjusted Netback (3)	($/boe)	21.83	20.68	13.89	20.09	16.82
Adjusted FFO Netback (4)	($/boe)	15.13	12.64	2.48	13.27	10.23
Capital expenditures (7)	($M)	111,213	48,563	64,707	236,401	169,135

1. *Net (loss) income attributable to equity holders of the Company.*
2. *Both basic and diluted weighted average numbers of common shares for the year ended December 31, 2017, were 50,005,832 (December 31, 2016: 50,002,363 and 50,018,997, respectively).*
3. *Refer to Non-IFRS Measures on page 20.*
4. *Adjusted Funds Flow from Operations ("**Adjusted FFO**") - Adjusted Funds Flow from Operations Netback ("**Adjusted FFO Netback**").*
5. *Net production after royalties represents the Company's working interest volumes, net of royalties and internal consumption.*
6. *BOE has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.*
7. *Capital expenditures includes E&E (defined below) revenues for the years ended December 31, 2017 and 2016, of $23.1 million and $13.7 million, respectively.*

Performance Highlights

Financial

- For the fourth quarter of 2017, total sales increased 9% to $335.3 million compared to $307.1 million in the third quarter of 2017, primarily due to stronger realized oil prices. The total sales value of $1,258.5 million in 2017 was lower than the $1,411.7 million in 2016, mainly due to lower realized gains from oil price risk management activities and lower volumes sold after the expiration of the Rubiales-Piriri contracts which governed the Company's right to exploit the Rubiales field, the Company's largest producing field in 2016.
- General and administrative costs ("**G&A**") costs were lower in the fourth quarter of 2017 at $24.5 million versus $26.6 million in the third quarter of 2017. In 2017, the Company continued efforts to reduce unnecessary overhead costs and minimize discretionary spending. Overall, G&A costs decreased 27% to $104.8 million from $144.5 million in 2016.
- During the fourth quarter of 2017, net loss attributable to equity holders of the Company was $32.5 million ($0.65/share), compared with a net loss of $141.1 million ($2.82/share) in the third quarter of 2017. This change was a result of the provision reversal related to the Corcel Block high-price clause ("**PAP**") of $99.6 million, lower impairment charges of $37.5 million and deferred income tax recovery of $20.8 million, offset by a higher unrealized risk management loss of $37.2 million and lower share of income from associates of $12.6 million in the fourth quarter of 2017. For 2017, net loss attributable to equity holders of the Company was $216.7 million ($4.33/share), compared with a net income of $2,448.5 million ($48.97/share) for 2016 due to the net gain on restructuring of $3,620.5 million recognized in the fourth quarter of 2016. Excluding the net gain on restructuring, the net loss for 2016 was $1,172.0 million higher than 2017.
- Operating EBITDA totalled $105.0 million ($2.10/share) for the fourth quarter of 2017, stable in comparison with the $105.9 million ($2.12/share) achieved in the third quarter of 2017, and $60.7 million higher than the fourth quarter of 2016 (mainly due to strong realized oil prices). In 2017, Operating EBITDA was $390.2 million, lower than the $444.6 million in 2016, mainly due to the expiration of the Rubiales-Piriri contracts in June 2016. Operating EBITDA exceeded the upwardly revised year-end guidance of $300 to $350 million.
- Adjusted FFO totalled $94.7 million ($1.89/share) for the fourth quarter of 2017, an increase of 98% compared to the $47.9 million ($0.96/share) achieved in the third quarter of 2017. For 2017, Adjusted FFO increased to $267.5 million from $257.0 million in 2016, mainly due to strong realized oil prices.
- The Company continued to build cash and the balance sheet remains strong at the end of 2017, with a cash position (including unrestricted cash equivalents) of $511.7 million, an increase of 32% from the previous year.
- On November 2, 2017, Fitch Ratings Inc. ("**Fitch**") raised its corporate credit rating on the Company to "B+" from "B" and the Senior Secured Notes ("**Senior Secured Notes**") debt rating to "BB-" from "B+"; as such, the rating outlook is stable. On November 29, 2017, Standard & Poor's Financial Services ("**S&P**"), upgraded its corporate and issue level credit rating to "BB-" from "B+", with a stable outlook.

Operational

- Net production after royalties for the fourth quarter of 2017 totalled 64,445 boe/d, lower than the previous quarter's volumes of 71,068 boe/d, primarily due to two factors: (i) an indigenous community claim against the Peruvian Government, which resulted in a community blockade on Block 192 that shut down operations between September 18, 2017 and November 9, 2017, and (ii) the natural production decline in the light and medium oil blocks. For 2017, the Company's net production after royalties was 70,082 boe/d, lower than the 103,532 boe/d in 2016, mainly due to the expiration of the Rubiales-Piriri contracts in June 2016.
- Realized oil prices were 11% higher quarter-over-quarter, averaging $56.00/bbl in the fourth quarter of 2017 versus $50.33/bbl in the previous quarter. In 2017, average realized crude oil prices were $50.82/bbl compared with $41.80/bbl in 2016. Frontera's increased realized oil prices were a result of the improved international oil prices at the end of 2017 and better differential prices over Brent prices from $6.44/bbl in 2016 to $4.32/bbl.
- Total operating costs (including production, PAP and royalties paid in cash, transportation and dilution costs) averaged $29.65/boe in the fourth quarter of 2017, an increase of 22% compared with $24.32/boe in the third quarter of 2017. Lower net production after royalties, higher transportation costs, higher production costs related to year-end community commitments, well services costs and road maintenance during the dry season meant higher total operating cost. From 2016, operating costs increased 17% to $26.25/boe in 2017, a result of lower volumes as a consequence of the Rubiales-Piriri contracts expiration in June 2016.
- Operating Netback was $23.61/boe for the fourth quarter of 2017, slightly higher than $23.54/boe in the third quarter of 2017. The Company's 2017 Operating Netback was 23% higher than the $17.89/boe achieved in 2016, mainly due to strong realized oil prices.
- Although the Company's drilling campaign was restrained during most of the year and only fully activated during the last quarter, intensive optimization activities allowed the Company to reach a net exit production rate of 71,015 boe/d, within the exit guidance range of 70,000 to 75,000 boe/d.

- In 2017, the Company received $11.3 million of cost reimbursement from unused take-or-pay transportation commitments by reversing the direction of the Bicentenario pipeline and transferring capacity to other shippers.
- Due to increased drilling activity, capital expenditures increased to $111.2 million in the fourth quarter of 2017 from $48.6 million in the third quarter of 2017. A total of 36 development wells and three exploration wells were completed in the fourth quarter of 2017. For 2017, capital expenditures were $236.4 million, higher than the $169.1 million in 2016, and resulting in a total of 94 completed development wells and three exploratory wells currently under evaluation. 2017 capital expenditure spending was below the low end of Frontera's guidance range of $250 to 300 million.
- The Company has been engaged for a number of years in an arbitration with the Agencia Nacional de Hidrocarburos ("**ANH**") regarding the application of the PAP clause in the Corcel Block, with the ANH claiming it was owed $167.2 million plus interest as at December 2012. On December 6, 2017, an arbitration panel delivered a ruling in favour of the Company's interpretation. As a result, given the settlement of the matter by the competent judge (the arbitration panel), the contingent liability previously recorded for the Corcel Block was reversed and a recovery of $99.6 million was recognized in the Consolidated Statements of (Loss) Income during the year ended December 31, 2017. On December 14, 2017, the ANH filed a request for annulment of the arbitration panel's decision with the Consejo de Estado (Colombia's highest administrative court), and the matter is currently being reviewed by this Court. Subsequent actions, including the annulment request, was assessed under IAS 37, and no provision was recognized as at December 31, 2017 given the initial stages of this new request and the existing ruling from the binding arbitration process in favour of the Company.

Corporate Development

- On October 13, 2017, the Company entered a share sale agreement with the International Finance Corporation (the "**IFC**") and funds related to the IFC (the "**IFC Parties**") pursuant to which the Company agreed to acquire the outstanding 36.36% of common shares in Pacific Midstream Limited ("**PML**") for the aggregate purchase price of $225.0 million, to be paid in installments over a 36-month period, including accrued interest on unpaid amounts (the "**Pacific Midstream Acquisition Agreement**"). The completion of the transaction is subject to obtaining modifications to certain take-or-pay contracts the Company has in place relating to the Bicentenario pipeline, among other customary conditions prior to closing. Pursuant to the Pacific Midstream Acquisition Agreement, should the transaction fail to close by October 13, 2018 as a result of the Company failing to satisfy certain conditions precedent, the Company will be required to pay a break fee in the aggregate amount of $5 million to the IFC Parties. The transaction is also subject to consent from the holders of the Company's Senior Secured Notes and lenders under the letter of credit facility Secured LC Agreement (defined below). Following the closing of this transaction PML will be a 100% consolidated entity of the Company.
- On October 25, 2017, the Company entered into an agreement to sell its interest in Petroelectrica de los Llanos ("**PEL**") to an affiliate of Electricas de Medellin-Ingeniería y Servicios S.A.S. Consideration for the sale will be $56.0 million in cash, of which $50.0 million will be used as the first payment to the IFC Parties in connection with the purchase of the IFC Parties' common shares in PML. On February 9, 2018, the Company received $20.0 million as an advance on the purchase price classified as restricted cash; however, neither the shares nor the promissory note will be transferred until closing. The completion of the transaction is subject to certain closing conditions that are expected to be met in the second quarter of 2018.
- On December 5, 2017, the Company received regulatory approval of its withdrawal and transfer of its interest in the petroleum prospect licence PPL 475 and petroleum retention licence PRL 39 in Papua New Guinea to InterOil Corporation (now ExxonMobil Canada Holdings ULC). On June 22, 2017, the Company entered into various agreements with InterOil Corporation pursuant to which the Company withdrew from and transferred its interest in the licences for the aggregate purchase price of $57.0 million. The transaction subsequently closed on February 20, 2018.
- In December 2017, the Company completed a corporate reorganization of its Colombian business units in an effort to streamline its operations and eliminate legal entity redundancies. All of Frontera's Colombian operations are now held by one entity: the Colombian branch of Frontera Energy Colombia Corp. (Colombian Branch) (formerly Meta Petroleum Corp. Colombian Branch), a wholly-owned subsidiary of the Company.

Management Changes

- On March 27, 2018, the Company announced the appointment of Director, Richard Herbert as Chief Executive Officer, effective April 2, 2018. Mr. Herbert will replace Barry Larson, who will step down as Chief Executive Officer effective April 2, 2018 but will remain with the Company until April 30, 2018 to assist with Mr. Herbert's transition into the role. Concurrently with his appointment, Mr. Herbert has resigned from the Board of Directors. In addition, the Company announced the appointment of David Dyck as Chief Financial Officer, effective April 2, 2018. Finally, the Company announced that Peter Volk has resigned as General Counsel and Secretary of the Company. Mr. Volk will be replaced by Margaret McNee, a senior partner at McMillan LLP, who has agreed to a secondment as the Company's acting general counsel, while the Company pursues the recruitment of a permanent replacement.

3. GUIDANCE

2018 Capital Expenditure Highlights

2018 will mark a year of significant investment for Frontera as the Company redeploys excess cash on its balance sheet to position itself for growth in 2019 and beyond. Total 2018 capital spending is budgeted at $450 to $500 million, representing a 101% year-over-year increase from $236 million in 2017. We expect the following ranges for our 2018 capital budget:

Capital Expenditures ($ Millions)	2017A	2018E	%chg
Maintenance and development drilling	$169	$225–240	38%
Facilities and infrastructure	$30	$125–140	342%
Exploration activities	$29	$100–120	279%
Other	$8	-	-%
Total capital expenditures budget	**$236**	**$450–500**	**101%**

Spending includes $225 to $240 million on maintenance and development (versus $169 million in 2017), $125 to $140 million on facilities (versus $30 million in 2017), and $100 to $120 million on exploration (versus $29 million in 2017). The maintenance and development budget incorporates the drilling of 125 to 135 development wells.

The significant increase in spending year-over-year is driven in part by a return to high-impact exploration. The Company's $100 to $120 million exploration budget includes the drilling of 6 to 8 exploration wells, including Frontera's first high-impact exploration well at Llanos 25 (Acorazado-1) in April. Production from this high-impact well will likely not be seen until 2019. In addition to Acorazado, Frontera's 2018 exploration budget includes the drilling of 5-7 additional exploration wells at Guatiquia, Mapache, Z1 (Peru), and Quifa blocks.

Facilities spending of $125 to $140 million also marks a significant increase year-over-year. Approximately 44% of Frontera's facilities budget is allocated to water handling facilities at Quifa, where liquids handling capacity is expected to increase to ~1.7 MMbbl/d by the fourth quarter of 2018 (up 31% from 1.3 MMbbl/d in 2017).

2018 Outlook & Guidance Highlights

	2017A	2018 Guidance
Brent ($/bbl)	**$54.79**	**$63.00**
Annual net production after royalties (boe/d)	70,082	65,000–70,000
Operating EBITDA ($MM) (1)	390	$375–425
Production costs ($/boe)	$10.78	$12.00–14.00
Transportation costs ($/boe)	$13.54	$12.50–14.50
General and administrative ($MM)	$105	$100–110

1. Operating EBITDA includes $68 million in expected realized losses from oil price risk management activities, assuming $63.00/bbl Brent oil price.

Assuming average Brent oil price for 2018 of $63.00/bbl and realized oil price differential of between $5.00/bbl and $5.50/bbl, the Company expects to deliver the following:

- Average and exit net production after royalties in 2018, is expected to be in the range of 65,000 boe/d to 70,000 boe/d (or between 72,000 boe/d to 76,000 boe/d before royalties);
- Operating EBITDA of $375 to $425 million, includes $68 million of expected losses from oil price risk management activities assuming flat $63.00/bbl Brent oil price in 2018;
- Annual per boe production costs of between $12.00/boe and $14.00/boe and transportation costs, excluding the impact of down time on the Bicentenario pipeline, of between $12.50/boe and $14.50/boe;
- Annualized G&A at $100 to $110 million;
- The Company has a portfolio of hedges for up to 60% of production in place up to October 2018 with average floor and ceiling prices between $51.3/bbl and $57.4/bbl.

First Quarter 2018 Operational Update

Average production in the first quarter of 2018 of approximately 66,000 boe/d is below previous guidance of 70,000 to 72,000 boe/d and reflects downtime associated with a social disruption on the Cubiro block in Colombia (~3,200 boe/d), and additional pay in kind royalty volumes at Quifa SW as a result of high price royalty program that applies when WTI is over $55.00/bbl (~1,700 boe/d). The blockade at Cubiro was lifted this week and our teams are working diligently to put the field back on full production.

The Company had nine rigs operating throughout the first quarter of 2018, with six active in its Quifa heavy oil area, and three on its light oil-focused Guatiquia Block. Frontera drilled 36 wells during the first quarter and undertook 26 workovers and well services, of which 33 were development-focused and three were exploration-focused. Frontera also initiated a water injection pressure maintenance project at Cubiro in January which is expected to help mitigate overall decline rates. We note that due to Frontera's success stabilizing its base production in 2017, the Company's corporate base decline rate has improved from 30 to 35% in 2017 to 25 to 30% at the beginning of 2018.

On the exploration front at Guatiquia Block, Frontera is pleased to announce success with its Alligator-2 exploration well. The well was flow tested for 8 days at an average rate of 1,380 bbl/d of oil with an average water cut of 28% at stabilized bottomhole flowing pressure with a 10% drawdown. The well was then shut-in for a two-day buildup. The well is currently producing at an stable average rate of 780 bbl/d of 22 degree API oil with an average water cut of 52%. Frontera plans to drill the follow-up Alligator-3 appraisal well from the same pad during the second quarter. Elsewhere at Guatiquia, the Coralillo exploration well reached a total depth of 11,500 feet on March 26, 2018, and is currently awaiting testing.

On the Quifa heavy oil trend, the Company completed its first vertical exploration well on its Jaspe block during the first quarter. The well was completed over 10 feet of the Basal Sand formation with an electrical submersible pump. The well was flow tested for 11 days at an average rate of 187 bbl/d of 13 degree API oil with an average water cut of 10% at stabilized bottomhole flowing pressure with a 14% drawdown. During the last 24 hours of test, the well averaged 174 bbl/d of oil and 30% water cut. As a result of this positive initial result at Jaspe Block, Frontera plans to drill two to three additional delineation wells on the prospect in 2018, and will consider a horizontal development program contingent on success. On the Quifa Southwest Block, the success of Frontera's vertical well delineation program has expanded Frontera's view of the known 2P and 3P reserves boundaries of the field. The 15 well vertical program (of which nine were drilled in 2017) was completed in January 2018, with each vertical well expected to potentially add five or six future horizontal development drilling locations.

At Llanos 25, well site preparation for the Company's high-impact well is underway with drilling expected to begin in April. The Company has signed an agreement with Helmerich & Payne, Inc. for a 3,000 horsepower H&P-900 rig. The drilling of the well is expected to take 90 to 120 days. As such, Frontera does not expect to be able to provide initial results until the third quarter of 2018.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2017, the Company received independent certified reserves evaluation reports ("**Reserves Reports**") for all of its assets, with total net 2P reserves of 154.3 MMboe compared with 170.7 MMboe certified reserves for the year ended 2016. The year-over-year decline was mainly caused by annual production, technical revisions in La Creciente field and an updated development plan for the Orito field. Proved net reserves of 114.1 MMboe now represent 74% of the total 2P reserves compared with 69% of the total 2P reserves in 2016.

The Reserves Reports were prepared in accordance with the definitions, standards, and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and the National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

Concurrently, with the filing of this MD& A, the Company has filed the following: (i) the Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1, (ii) Report on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101F2 by each of RPS Energy Canada Ltd. and DeGolyer and MacNaughton, and (iii) the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3. These reports have been filed on SEDAR at www.sedar.com.

Reserves at December 31, 2017 (MMboe[1])								
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Quifa SW	49.0	42.6	1.9	1.6	50.9	44.2	Heavy oil
	Other heavy oil blocks [2]	34.6	30.4	15.1	13.3	49.7	43.6	Heavy oil
	Light/medium oil blocks [3]	38.2	35.1	21.0	19.2	59.1	54.3	Light and medium oil, associated natural gas
	Natural gas blocks [4]	1.9	1.9	1.3	1.3	3.2	3.2	Natural gas
	Sub-total	**123.6**	**109.9**	**39.2**	**35.4**	**162.9**	**145.3**	Oil and natural gas
Peru	Light/medium oil and natural gas [5]	5.1	4.3	4.8	4.7	9.8	9.0	Light and medium oil, associated natural gas
	Total at Dec. 31, 2017	**128.7**	**114.1**	**44.0**	**40.2**	**172.7**	**154.3**	Oil and natural gas
	Total at Dec. 31, 2016	131.8	117.3	58.5	53.4	190.3	170.7	
	Difference	**(3.1)**	**(3.2)**	**(14.6)**	**(13.3)**	**(17.7)**	**(16.5)**	
	2017 Production	**27.4**	**25.5**	**Total reserves incorporated**		**9.8**	**9.0**	

1. See "Boe conversion" in the "Further Disclosures" section, page 31.
2. Includes Cajua, Jaspe, Quifa North, Sabanero and CPE-6 Blocks.
3. Includes Cubiro, Cravo Viejo, Canaguaro, Guatiquia, Casimena, Corcel, Neiva, Cachicamo, and other producing blocks.
4. Includes La Creciente and Guaduas Blocks.
5. Includes onshore Block 192 and offshore Block Z1.

In the table above, "Gross" refers to working interest before royalties, and "Net" refers to working interest after royalties. Numbers in the table may not add due to rounding differences.

5. FINANCIAL AND OPERATIONAL RESULTS

Production and Development Review

The following tables highlight the average daily total field production, the gross share before royalties production and the net production after royalties from all of the Company's producing fields in Colombia and Peru, reconciled to volume sold.

	Average Production (in boe/d)								
	Total field production			Gross share before royalties [1]			Net production after royalties		
Producing fields in Colombia	**Q4 2017**	**Q3 2017**	**Q4 2016**	**Q4 2017**	**Q3 2017**	**Q4 2016**	**Q4 2017**	**Q3 2017**	**Q4 2016**
Light and medium [2]	34,465	37,545	40,448	32,747	35,996	38,202	30,142	33,105	35,182
Heavy oil [3]	47,798	46,491	44,756	28,972	28,090	27,193	26,451	25,731	24,968
Gas [4]	6,074	6,139	8,248	5,315	5,427	7,203	5,314	5,427	7,203
Total production Colombia	**88,337**	**90,175**	**93,452**	**67,034**	**69,513**	**72,598**	**61,907**	**64,263**	**67,353**
Producing fields in Peru									
Light and medium [5]	4,175	10,198	5,411	2,538	6,805	2,079	2,538	6,805	2,079
Total production Peru	**4,175**	**10,198**	**5,411**	**2,538**	**6,805**	**2,079**	**2,538**	**6,805**	**2,079**
Total production Colombia and Peru	**92,512**	**100,373**	**98,863**	**69,572**	**76,318**	**74,677**	**64,445**	**71,068**	**69,432**

1. *Share before royalties is net of internal consumption at the field and before high-price clause ("**PAP**") at the Quifa SW field. The Company's share before royalties in the Quifa SW field is 60% and decreases in accordance with a PAP that assigns additional production to Ecopetrol.*
2. *Includes Cubiro, Cravo Viejo, Casanare Este, Canaguaro, Guatiquia, Casimena, Corcel, CPI Neiva, Cachicamo, Arrendajo, and other producing blocks.*
3. *Includes Quifa, Cajua, Sabanero, CPE-6, and Rio Ariari Blocks.*
4. *Includes La Creciente and Guama Blocks.*
5. *Includes Block Z1, Block 192 and Block 131. On May 12, 2017, Block 131 was formally transferred to Cepsa. As a result, production from this block was included until May 19, 2017.*

	Average Production (in boe/d)					
	Total field production		Gross share before royalties [1]		Net production after royalties	
Producing fields in Colombia	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Light and medium [2]	37,454	44,378	35,756	41,893	32,888	39,607
Heavy oil [3]	48,413	50,855	29,386	30,847	26,879	28,195
Gas [4]	6,603	9,767	5,784	8,763	5,784	8,763
Rubiales-Piriri	—	71,453	—	29,826	—	23,861
Total production Colombia	**92,470**	**176,453**	**70,926**	**111,329**	**65,551**	**100,426**
Producing fields in Peru						
Light and medium [5]	7,638	6,542	4,530	3,106	4,531	3,106
Total production Peru	**7,638**	**6,542**	**4,530**	**3,106**	**4,531**	**3,106**
Total production Colombia and Peru	**100,108**	**182,995**	**75,456**	**114,435**	**70,082**	**103,532**
Total production excluding Rubiales-Piriri	**100,108**	**111,542**	**75,456**	**84,609**	**70,082**	**79,671**

Note: Footnotes refer to those from the quarterly production table above.

Net production after royalties reconciled to volume sold		Q4 2017	Q3 2017	Q4 2016	2017	2016
Net production after royalties [1]	**(boe/d)**	**64,445**	**71,068**	**69,432**	**70,082**	**103,532**
Oil inventory build [2]	(bbl/d)	1,633	(7,283)	(953)	(3,341)	(8,040)
Trading and diluent volumes purchased [3]	(boe/d)	3,924	7,201	2,544	6,092	1,282
E&E assets volumes sold [4]	(boe/d)	(1,420)	(1,075)	(1,370)	(1,362)	(1,278)
Trading volumes sold [5]	(boe/d)	(3,101)	(6,749)	(2,183)	(5,491)	(780)
Sales volumes	**(boe/d)**	**65,481**	**63,162**	**67,470**	**65,980**	**94,716**
Oil sales	(bbl/d)	60,279	57,808	60,732	60,384	86,343
Gas sales [6]	(mcf/d)	29,651	30,518	38,407	31,895	47,721

1. *Net production after royalties represents the Company's working interest volumes, net of royalties and internal consumption.*
2. *Produced volumes that were not sold in the period and instead resulted in an increase in crude inventories held in storage.*
3. *Volumes purchased for trading and diluent purposes to fulfill pipeline take-or-pay agreements and pipeline quality specifications.*
4. *Volumes from E&E assets are excluded from total sales volumes because E&E revenues and costs are capitalized under IFRS.*
5. *Trading volumes sold that were purchased to meet volumes required for pipeline take or pay agreements.*
6. *BOE has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.*

Net production after royalties for the fourth quarter of 2017 totalled 64,445 boe/d, lower than the previous quarter's volumes of 71,068 boe/d, primarily due to two factors: (i) an indigenous community claim against the Peruvian Government, which resulted in a community blockade on Block 192 that shut down operations between September 18, 2017 and November 9, 2017, and (ii) the natural production decline in the light and medium oil blocks. For 2017, the Company's net production after royalties was 70,082 boe/d, lower than the 103,532 boe/d in 2016, mainly due to the expiration of the Rubiales-Piriri contracts in June 2016.

Colombia

During the fourth quarter of 2017, light and medium net oil production after royalties averaged 30,142 boe/d, lower than the previous quarters, again due to natural production decline. In the fourth quarter alone, the Company completed a total of five development wells on light and medium blocks: Guatiquia, Cubiro and Cravo viejo. In 2017, light and medium net oil production after royalties averaged 32,888 boe/d, a reduction from the 39,607 boe/d produced in 2016 mainly due to the natural production decline in the light and medium oil blocks. In 2017, the Company completed a total of 12 development wells on its light and medium blocks: Guatiquia, Cubiro, Mapache and Cravo viejo.

During the fourth quarter of 2017, heavy net oil production after royalties averaged 26,451 boe/d, higher than the previous quarters. During the fourth quarter, the Company completed a total of 34 development wells on heavy oil blocks: Quifa and CPE-6. In 2017, heavy net oil production after royalties averaged 26,879 bbl/d, slightly lower than the 28,195 bbl/d produced in 2016. In 2017, the Company completed a total of 81 development wells on heavy oil blocks: Quifa, Cajua and CPE-6.

In September 2017, the Company began a more aggressive drilling campaign, incorporating additional rigs into its work program. As a result of this increased activity, the Company drilled 52% more feet during the fourth quarter of 2017 compared with the third quarter of 2017, representing 39% of all feet drilled in 2017.

Peru

During the fourth quarter of 2017, net production after royalties was 2,538 bbl/d, a 63% decrease from 6,805 bbl/d in the third quarter of 2017. Beginning on September 18, 2017, production on Block 192 was halted until November 9, 2017 due to an indigenous community claim against the Peruvian Government; production reached a total of 8,244 bbl/d net production at the end of the year. In 2017, net production after royalties was 4,531 bbl/d, an increase of 46% from 3,106 bbl/d in 2016, mainly as a result of the production halt from February 23, 2016 to January 31, 2017 due to a force majeure at the block arising from the shutdown of the Norperuano pipeline.

Operational Update

During the fourth quarter of 2017, the Company integrated technical studies and detailed reservoir management work into its operation. As a result, the Company made significant progress towards increasing the value add of reservoir managing its producing assets. The significant changes to reservoir management made in the third quarter are now showing positive results towards slowing overall production decline. In addition, the Company successfully completed reservoir injection tests to prove the potential for secondary recovery and reservoir pressure support. These studies and optimization activities propelled the Company toward accomplished more cost-efficient development and production operations. In 2017, the following producing blocks were positively affected by this work:

- Quifa and Cajua Blocks – Reservoir studies were integrated to increase the success rate for drilling wells in higher oil-producing zones within the reservoirs. In addition, changes to drilling and completion practices have increased overall well productivity. Successful wells were drilled outside of the current mapped field boundaries, thereby defining new development well locations.
- Guatiquia Block – Development drilling continued in the fourth quarter of 2017 with excellent results, confirming the high productivity of the two main producing reservoirs. The drilling results are very encouraging and have opened up the potential for future development well locations. Preparations for the drilling of injector wells for reservoir pressure maintenance continued, and as a result, the first injector well in the Ardilla field was spud to assist with arresting production decline and increasing the recovery factor.
- Orito and Neiva Blocks – The Company continues to monitor the new pilot water injection program implemented at the Neiva Block in an effort to enhance recovery. The initial results are encouraging and to date there has been a significant increase in production. Based on these positive results, the Company is considering an expansion of this program. Reservoir studies are underway to possibly implement a similar water injection program at the Orito Block.
- Cubiro Block – Due to the various successful reservoir injection tests, the Company was able to confirm that selected injector wells will be able to effectively provide reservoir pressure support by receiving significant volumes of water.

Netbacks

The Company's netbacks are summarized below. For discussion on the definitions of how the Company uses Operating Netback, Adjusted Netback and Adjusted FFO Netback, please refer to page 20, "Non-IFRS Measures."

	Q4 2017		Q3 2017		Q4 2016	
	($/boe)	$M	($/boe)	$M	($/boe)	$M
Oil and natural gas sales price [1]	**53.26**	**320,868**	**47.86**	**278,137**	**41.92**	**260,179**
Production cost of barrels	(13.13)	(77,860)	(10.85)	(70,940)	(11.45)	(73,156)
PAP and royalties paid in cash	(1.23)	(7,305)	(0.62)	(4,047)	(0.92)	(5,893)
Transportation (trucking and pipeline)	(14.28)	(84,682)	(11.77)	(76,931)	(14.52)	(92,754)
Dilution cost	(1.01)	(6,016)	(1.08)	(7,052)	(0.51)	(3,285)
Total operating cost [2]	**(29.65)**	**(175,863)**	**(24.32)**	**(158,970)**	**(27.40)**	**(175,088)**
Operating Netback	**23.61**	**145,005**	**23.54**	**119,167**	**14.52**	**85,091**
Fees paid on suspended pipeline capacity [2]	(4.16)	(24,656)	(5.33)	(34,838)	(2.92)	(18,648)
Share of income from associates – pipelines [3]	2.38	14,130	2.47	16,135	2.29	14,616
Adjusted Netback	**21.83**	**134,479**	**20.68**	**100,464**	**13.89**	**81,059**
General and administrative expenses [4]	(4.12)	(24,450)	(4.06)	(26,569)	(6.21)	(39,640)
Cash finance costs [5]	(1.05)	(6,250)	(0.96)	(6,250)	(1.47)	(9,361)
Other cash costs [6]	(1.53)	(9,083)	(3.02)	(19,756)	(3.73)	(23,802)
Adjusted FFO Netback	**15.13**	**94,696**	**12.64**	**47,889**	**2.48**	**8,256**
Total production volume (boe/d) [7]	64,445		71,068		69,432	
Sales volume (D&P) (boe/d) [8]	65,481		63,162		67,470	

For reconciliation to IFRS figures:
1. *Per boe price calculated over sales volume D&P, refer to page 12.*
2. *Operating costs, refer to page 13.*
3. *Share of income from associates – pipelines, refer to page 15.*
4. *General and administrative costs, refer to page 15.*
5. *Finance costs, refer to page 15.*
6. *Mainly includes: dividends from associates, Frontera's share of income (loss) from associates, income tax, equity tax paid, realized foreign exchange, inventory fluctuation, overlift/(settlement) and uses of asset retirement obligation.*
7. *Production and development review, refer to page 8.*
8. *Sales volumes D&P excludes E&E as the revenues and costs are capitalized under IFRS.*

Operating Netback was $23.61/boe for the fourth quarter of 2017, slightly higher in comparison with $23.54/boe in the third quarter of 2017, and 63% higher than $14.52/boe in the fourth quarter of 2016, due to strong realized oil prices, offset by higher operating costs. The main drivers of higher total operating costs were higher transportation costs from increased utilization of the Bicentenario pipeline, which has a higher tariff than the Oleoducto Central S.A. ("**OCENSA**") pipeline. Additionally, higher production costs resulted from year-end social investment commitments, well services costs and road maintenance during the dry season.

Adjusted Netback in the fourth quarter of 2017 was $21.83/boe, 6% higher than $20.68/boe in the third quarter of 2017 and 57% higher than $13.89/boe in the fourth quarter of 2016. The increase in comparison with the previous quarter was mainly related to higher Operating Netback and lower fees paid on suspended pipeline capacity as the Bicentenario system was not operational for only 56 days compared with 75 days. The cost redundancy from unused pipeline take-or-pay commitments decreased Adjusted Netback by $4.16/boe ($24.7 million) in the fourth quarter of 2017.

Adjusted FFO Netback was $15.13/boe for the fourth quarter of 2017, higher than $12.64/boe in the previous quarter, and $2.48/boe in the fourth quarter of 2016, mainly due to higher G&A and cash finance costs in the quarter.

	Year Ended December 31			
	2017		2016	
	($/boe)	$M	($/boe)	$M
Oil and natural gas sales price (1)	**48.32**	**1,163,749**	**40.36**	**1,399,120**
Production cost of barrels	(10.78)	(275,717)	(8.27)	(313,496)
PAP and royalties paid in cash	(0.87)	(22,147)	(0.59)	(22,269)
Transportation (trucking and pipeline)	(13.54)	(346,300)	(12.16)	(460,605)
Dilution cost	(1.06)	(27,162)	(1.45)	(55,108)
Total operating cost (2)	**(26.25)**	**(671,326)**	**(22.47)**	**(851,478)**
Operating Netback	**22.07**	**492,423**	**17.89**	**547,642**
Fees paid on suspended pipeline capacity (2)	(4.25)	(108,831)	(2.77)	(105,129)
Share of income from associates – pipelines (3)	2.27	58,150	1.70	64,327
Adjusted Netback	**20.09**	**441,742**	**16.82**	**506,840**
General and administrative expenses (4)	(4.10)	(104,823)	(3.81)	(144,538)
Cash finance costs (5)	(0.98)	(25,000)	(3.27)	(123,779)
Other cash costs (6)	(1.74)	(44,423)	0.49	18,449
Adjusted FFO Netback	**13.27**	**267,496**	**10.23**	**256,972**
Total production volume (boe/d) (7)	70,082		103,532	
Sales volume (D&P) (boe/d) (8)	65,980		94,716	

For reconciliation to IFRS figures:

1. *Per boe price calculated over sales volume D&P, refer to page 12.*
2. *Operating costs, refer to page 13.*
3. *Share of income from associates – pipelines, refer to page 15.*
4. *General and administrative costs, refer to page 15.*
5. *Finance costs, refer to page 15.*
6. *Mainly includes: dividends from associates, Frontera's share of income (loss) from associates, income tax, equity tax paid, realized foreign exchange, inventory fluctuation, overlift/(settlement) and uses of asset retirement obligation.*
7. *Production and development review, refer to page 8.*
8. *Sales volumes D&P excludes E&E as the revenues and costs are capitalized under IFRS.*

Although operating costs were higher in 2017, Operating Netback was $22.07/boe for 2017, an increase of 23% in comparison with $17.89/boe in 2016, mainly due to higher realized oil prices in 2017. The main driver of higher operating costs was lower production volume due to the expiration of the Rubiales-Piriri contracts in June 2016. This was partially offset by the cost reimbursement of $11.3 million from the Bicentenario pipeline when third parties used the bidirectional pipeline.

Adjusted Netback was $20.09/boe for 2017, 19% higher than $16.82/boe in 2016. The increase was a result of an improved Operating Netback driven by higher realized oil prices and, higher share of income from associates and offset by higher fees paid on suspended pipeline capacity as the Bicentenario system was not operational for 229 days as compared with 187 days in the previous year.

Adjusted FFO Netback was $13.27/boe for 2017, higher than $10.23/boe in 2016, due to higher Adjusted Netback and lower cash finance costs mainly due to the reduction of total debt obligations to $250.0 million from $5.8 billion as a result of the Restructuring Transaction (defined below).

Realized and Reference Prices

	Q4 2017	Q3 2017	Q4 2016	2017	2016
Reference prices					
Brent ($/bbl)	61.54	52.17	51.06	54.79	45.13
Average realized prices					
Realized oil price ($/bbl)	56.00	50.33	43.78	50.82	41.80
Realized natural gas price ($/Mcf)	3.78	3.73	4.41	3.76	4.48
Realized natural gas price ($/boe) (1)	21.55	21.26	25.12	21.43	25.52
Combined price before hedging/other ($/boe)	**54.88**	**46.33**	**42.48**	**48.01**	**35.56**
Realized hedging (loss) gain ($/boe)	(2.93)	0.31	(1.52)	(0.88)	4.39
Other revenue ($/boe) (2)	1.31	1.22	0.96	1.19	0.41
Combined realized price ($/boe)	**53.26**	**47.86**	**41.92**	**48.32**	**40.36**

1. *Refer to the section entitled "Further Disclosures" on page 31 for conversion factor.*
2. *Mainly includes income from infrastructure asset.*

Crude oil prices continued to improve in 2017, with the Brent price averaging $54.79/bbl as compared to $45.13/bbl in 2016, representing an increase of 21.40% or $9.66/bbl. Stronger crude oil prices were driven by higher global demand and lower global production levels as a result of the Organization of Petroleum Exporting Countries' ("**OPEC**") recent decisions on the reduction of oil production levels of OPEC member countries and non-OPEC member countries' decision to follow suit. The higher than expected compliance rates with production cuts have resulted in reduced global crude oil inventories, which had depressed prices throughout 2016.

During 2017, the differential between the Company's Vasconia crude oil sales and Brent narrowed by $2.12/bbl as compared with 2016. The tightening in the differentials was the result of new market strategies that focused on negotiating directly with final consumers, allowing the Company to improve sales prices. Additionally, throughout the first half of the year, a significant deficit of crude barrels in the U.S. West Coast market boosted oil demand in the region, especially from Latin America, leading to further improvement in the Company's sales prices relative to global benchmarks.

Sales

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	2017	2016	2017	2016
Oil and gas sales and other income	$ 338,509	269,620	1,185,040	1,247,004
(Loss) gain from oil price risk management activities	(17,641)	(9,441)	(21,291)	152,116
Trading revenue	14,478	9,593	94,767	12,591
Total sales	**$ 335,346**	**269,772**	**1,258,516**	**1,411,711**
Total sales excluding trading revenue	320,868	260,179	1,163,749	1,399,120
$/per volume sold	53.26	41.92	48.32	40.36

Total sales during the fourth quarter of 2017 were $335.3 million, 24% higher than the same period of 2016, mainly due to stronger realized oil prices. Total sales for 2017 was $1,258.5 million, 11% lower than 2016, mainly due to lower volumes sold caused by the expiration of the Rubiales-Piriri contracts and lower realized gains from oil price risk management activities.

The following is an analysis of the price and sales volume movements for the fourth quarter of 2017 compared with the same period of 2016, and for the year ended December 31, 2017 and 2016:

(in thousands of US$)		Three Months Ended December 31
Total sales for the three months ended December 31, 2016	$	269,772
Decrease due to 3% (1,989 boe/d) reduction in produced and sold volumes		(7,773)
Increase due to 918 bbl/d higher volume of trading		4,034
Oil price risk management activities effect		(8,200)
Increase due to 29% higher realized prices		75,865
Other revenue increase		1,648
Total sales for the three months ended December 31, 2017	**$**	**335,346**

(in thousands of US$)		Year Ended December 31
Total sales for the year ended December 31, 2016	$	1,411,711
Decrease due to 31% (28,917 boe/d) lower produced and sold volumes		(376,348)
Increase due to 5,245 bbl/d higher volume of trading		68,027
Oil price risk management activities effect		(173,407)
Increase due to 35% higher realized prices		314,177
Other revenue increase		14,356
Total sales for the year ended December 31, 2017	**$**	**1,258,516**

Operating Costs

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	**2017**	**2016**	**2017**	**2016**
Production costs	$ 77,860	$ 73,156	$ 275,717	$ 313,496
PAP and royalties paid in cash	7,305	5,893	22,147	22,269
Transportation costs	84,682	92,754	346,300	460,605
Dilution cost	6,016	3,285	27,162	55,108
Total operating cost	**$ 175,863**	**$ 175,088**	**$ 671,326**	**$ 851,478**
Average operating cost $/per boe production	**29.65**	**27.40**	**26.25**	**22.47**
Fees paid on suspended pipeline capacity	24,656	18,648	108,831	105,129
Purchase of oil and gas for trading	14,403	9,104	93,577	11,515
Other costs (1)	(613)	1,713	(22,076)	(5,593)
Overlift (settlement)	16,927	(48)	17,008	(34,864)
Reversal of provision related to high-price clause	(99,622)	—	(99,622)	—
Post-termination Rubiales Block	(694)	—	3,664	—
Total cost	**$ 130,920**	**$ 204,505**	**$ 772,708**	**$ 927,665**

1. Other costs mainly correspond to inventory fluctuation.

Total operating costs for the fourth quarter of 2017 were $175.9 million, stable in comparison with $175.1 million in the same period of 2016. For 2017, total operating costs were $671.3 million, a 21% reduction from $851.5 million in 2016, mainly due to the expiration of the Rubiales-Piriri contracts which, as mature fields, had lower costs than others.

Total operating costs averaged $29.65/boe in the fourth quarter of 2017, an increase of 8% compared with $27.40/boe in the third quarter of 2017. The main drivers of these higher total operating costs were: higher transportation costs, higher production costs related to year-end community commitments, well services costs and road maintenance during the dry season. For 2017, total operating costs averaged $26.25/boe, higher compared with $22.47/boe from 2016, mainly due to lower produced volumes from expiration of the Rubiales-Piriri contracts.

Total costs for the fourth quarter of 2017 were $130.9 million, compared to $204.5 million for the same period in 2016. The decrease of $73.6 million was primarily due to the reversal of provision related to the Corcel Block high-price clause of $99.6 million offset by overlift expense of $16.9 million in 2017 (versus settlement income recognized in the comparative period). In 2017, total costs were $772.7 million, which was a decrease of $155.0 million from the prior year. The decrease was mainly due to lower year-over-year operating costs of $180.2 million and reversal of provision related to the Corcel Block high-price clause of $99.6 million, offset by increases in purchase and gas sales trading of $82.1 million and recognition of overlift expense of $17.0 million in the year ($34.9 million settlement income was recognized in the prior year).

Depletion, Depreciation and Amortization

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	2017	2016	2017	2016
Depletion, depreciation, and amortization	$ 95,062	$ 85,700	$ 382,246	$ 575,985
$/per boe production	16.03	11.74	14.94	16.67

Depletion, depreciation and amortization ("**DD&A**") increased to $95.1 million in the fourth quarter of 2017 compared with $85.7 million in the same quarter of 2016, mainly from larger investment in production facilities and exploration activities during the last quarter of 2017. Total 2017 DD&A decreased to $382.2 million from $576.0 million in 2016. The decrease was mainly due to the lower depletable base after the impairments recorded in 2016 and the change in the depletion calculation over the Company's proved and probable reserves in 2017 (2016: proved reserves). Unit DD&A for the fourth quarter of 2017 was $16.03/boe, 37% higher compared with the same period of 2016, due to lower production compared with the previous year. For 2017, DD&A per barrel was $14.94/boe, compared with $16.67/boe for 2016, as a result of a higher base from the Rubiales-Piriri contracts during the first half of 2016.

Impairment

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	2017	2016	2017	2016
Impairment (reversal) of oil and gas properties, exploration and evaluation assets and plant and equipment	$ 28,414	$ (636,952)	$ 72,789	$ 294,259
Impairment of assets held for sale - PEL	1,035	—	42,194	—
Impairment of other assets (advances and Bicentenario prepayments)	—	(7,299)	—	166,147
Impairment of short term receivables and others	7,019	7,657	8,197	16,599
Total impairment (reversal)	**$ 36,468**	**$ (636,594)**	**$ 123,180**	**$ 477,005**

During 2017, an impairment charge of $72.8 million ($294.3 million in 2016) was recognized with respect to certain oil and gas properties, E&E assets from the Colombia Cash Generating Units ("**CGU**") and other infrastructure assets in Colombia. The carrying value was written down to a recoverable amount calculated based on the Value in Use.

At the end of each reporting period, the Company assesses whether there is any indication, from external and internal sources, that an asset or CGU may be impaired. The Company considers changes in the market, the economic and legal environments in which the Company operates that are not within its control and exploration and evaluation properties. The impairment tests of oil and gas and E&E assets are performed at the CGU level.

Assumptions used in the model to determine the recoverable amounts include:

- An after-tax discount rate of 14.64% (24.36% before tax) (2016: 18%, 30% before tax) as determined by the weighted average cost of capital taking into consideration the expected return on investment by the Company's investors, the cost of debt based on the interest-bearing borrowings of the Company and segment specific risk based on publicly available market data.
- Long-term Brent oil prices of $62, $63, $66, $70 and $73 per barrel for 2018 to 2022, respectively (2016: $56, $61, $65, $68 and $72 per barrel for 2017 to 2021) and Guajira Block regulated benchmark gas prices of $4, $4, $5, $5 and $5 per thousand cubic feet for 2018 to 2022, respectively (2016: $3, $4, $4, $4 and $4 per thousand cubic feet for 2017 to 2021), inflated by approximately 2% (2016: 2%) subsequent to that period. Prices are based on futures strip prices (2016: compilation of independent industry analyst forecasts), published indices and management's own assumptions.

- Future production is based on proved developed producing, proved developed non-producing and probable reserves (2016: proved developed producing and proved developed non-producing reserves).

During 2017, a total impairment charge of $42.2 million was recognized based on bidding offers with respect to the transmission line assets of PEL. The recoverable amount was calculated using fair value less costs of disposal. An agreement to sell PEL for proceeds of $56.0 million was entered into on October 25, 2017. The carrying value was ultimately written down to a recoverable amount consistent with the sale consideration. As a result of the approval of the sale transaction, the PEL assets were classified as held-for-sale (Please refer to Note 10 in the Consolidated Financial Statements).

During 2016, the Company recorded an impairment charge of $166.1 million related to advances or pre-payments of Oleoducto Bicentenario de Colombia S.A.S. and others of $106.5 million, based on updated production forecasts, and $59.6 million related to long-term recoverable valued added tax (“**VAT**”) receivable balances for which the Company had determined it was more likely than not the amounts would not be recovered through future production on certain blocks.

During 2017, the Company recognized $8.2 million compared to $16.6 million in 2016, of certain accounts receivable considered as doubtful recovery and other impairments mainly related to low rotation or obsolete inventories.

General and Administrative Costs

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	**2017**	**2016**	**2017**	**2016**
General and administrative costs	$ 24,450	$ 39,640	$ 104,823	$ 144,538
$/per boe production	4.12	6.21	4.10	3.81

G&A costs for 2017 decreased to $104.8 million from $144.5 million in 2016 as a result of the Company’s continued efforts to reduce unnecessary overhead costs and minimize discretionary spending. During the fourth quarter of 2017, G&A costs decreased to $24.5 million from $39.6 million in the same period of 2016.

Non-Operating Costs

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	**2017**	**2016**	**2017**	**2016**
Cash finance costs	(6,250)	(9,361)	(25,000)	(123,779)
Non-cash finance income (cost)	772	(57,136)	832	(67,466)
Total finance costs	**(5,478)**	**(66,497)**	**(24,168)**	**(191,245)**
Cash finance costs $/per boe production	(1.05)	(1.47)	(0.98)	(3.27)
Share of income from associates - pipelines	14,130	14,617	58,150	64,329
Share of income (loss) from associates - other	679	(18,870)	18,036	(1,489)
Total share of income (loss) from associates, net of impairment	**14,809**	**(4,253)**	**76,186**	**62,840**
Share of income from associates - pipelines $/per boe production	2.38	2.29	2.27	1.70
Foreign exchange (loss) gain	**(3,472)**	**(13,857)**	**1,876**	**8,863**
(Loss) on risk management	**(80,774)**	**(13,471)**	**(71,762)**	**(139,457)**
Current income tax expense	(10,392)	(1,113)	(36,095)	(42,522)
Deferred income tax recovery: Relating to origination and reversal of temporary differences	20,830	3,891	20,830	6,347
Total income tax (expense) recovery	**10,438**	**2,778**	**(15,265)**	**(36,175)**
Income tax expense $/per boe production	**1.76**	**0.43**	**(0.60)**	**(0.95)**
Restructuring cost	1,589	30,092	4,263	121,608
Severance	847	24,942	8,354	33,247
Total restructuring and severance costs	**2,436**	**55,034**	**12,617**	**154,855**

Finance Costs

Finance costs include interest on the Company's long-term debt, working capital loans, finance leases and fees on letters of credit, net of interest income received. During 2017, finance costs decreased to $24.2 million from $191.2 million in 2016. This was mainly due to the change in the Company's capital structure, reducing financial debt to $250.0 million as part of the Restructuring Transaction (defined below).

Share of Income from Associates

During 2017, the Company's share of income from associates increased to $76.2 million from $62.8 million in 2016, mainly due to the lower loss of Pacific Infrastructure Ventures Inc., which had lower foreign exchange losses in 2017 compared with 2016.

Foreign Exchange

Foreign exchange gains or losses primarily result from the movement of the Colombian peso ("**COP**") against the U.S. dollar. A significant portion of the Company's working capital and expenditures are denominated in COP. During 2017, the COP appreciated against the U.S. dollar by 0.6% (foreign exchange close rate COP–U.S. dollar was COP$2,984.00 for 2017, and COP$3,000.71 for 2016). The foreign exchange gain in 2017 was $1.9 million compared with a gain of $8.9 million in 2016 primarily due to the impact of the COP's appreciation on the translation of the Company's net working capital.

Loss on Risk Management

As part of its risk management strategy, the Company entered into oil price risk management contracts to hedge against oil price volatility. For the year ended December 31, 2017, the Company hedged 60% of its estimated production. The Company is currently advancing its hedging program for 2018, and for the end of 2017 there were open positions up to October 2018. The objective for 2018 is to hedge the maximum available to be hedged under the Note Indenture and Secured LC Agreement of 60% of the Company's planned production; however, this is constantly re-evaluated in the context of current prices, market expectations and changes in the production forecast.

The hedging portfolio consists of zero-cost collars and call spread instruments. As at December 31, 2017, the Company had outstanding finance hedge positions for approximately 12 MMbbl with average floor and ceiling strike prices of $51.30/bbl and $57.38/bbl Brent, respectively, with a net liability of $104 million.

					Carrying Amount (in thousands of US$)	
Type of Instrument	**Settlement Month**	**Benchmark**	**Notional Amount / Volume (bbl/d)**	**Put/ Call Strike**	**Assets**	**Liabilities**
Commodities Price Risk						
Collar	January 2018	Brent	1,200,000	49.11 / 55.45	—	13,663
Collar	February 2018	Brent	1,200,000	49.95 / 55.28	—	13,376
Collar	March 2018	Brent	1,200,000	50.06 / 55.37	—	12,946
Collar	April 2018	Brent	1,200,000	50.77 / 55.73	—	12,294
Collar	May 2018	Brent	1,200,000	51.10 / 55.86	—	11,924
Collar	June 2018	Brent	1,200,000	51.23 / 55.91	—	11,611
Collar	July 2018	Brent	1,200,000	52.00 / 59.31	—	8,116
Collar	August 2018	Brent	1,200,000	52.42 / 60.05	—	7,179
Collar	September 2018	Brent	1,200,000	53.42 / 61.63	—	5,507
Collar/ Call Spreads	October 2018	Brent	1,200,000	52.92 / 59.22	—	7,131
Total as at December 31, 2017					**$ —**	**$ 103,747**

Income Tax Expense

The current income tax expense for the fourth quarter of 2017 was $10.4 million, offset by an income tax recovery of ($20.8) million related to the recognition of a deferred tax asset. The current income tax expense included minimum income tax ("presumptive tax") of $10.3 million, current tax in countries other than Colombia of $0.7 million, and a reduction in expected income tax receivables of $(0.6) million. The deferred income tax asset arose primarily from deductible temporary differences associated with undepreciated capital expenses related to oil and gas properties.

The current income tax expense for the year ended December 31, 2017 totalled $36.1 million compared to $42.5 million in the same period in 2016. The variation is mainly attributable to the decrease in profits before tax in the Colombian entities, which were subject to presumptive tax. The current income tax expense consists of $35.3 million of current tax in Colombia, current tax in countries other than Colombia of $1.3 million, and a recovery of the income tax receivables for ($0.5) million. The current income tax expense in 2017 was offset by ($20.8) million of deferred income tax recovery related to the recognition of a deferred tax asset in the fourth quarter.

During 2017, the Company paid $11.7 million related to the Colombian wealth tax.

Restructuring and Severance Costs

During the year ended December 31, 2016, the Company incurred $154.9 million in costs related to the Restructuring Transaction (defined below) and severances for work force reductions, including costs related to retention bonuses for certain officers and employees. During the year ended December 31, 2017, the Company incurred $12.6 million in restructuring and severance costs ($8.3 million) and corporate simplification activities ($4.3 million).

Following the Restructuring Transaction, the new Board of Directors and the new management embarked in a plan to transform operations based on a continuous improvement process, including operational efficiency, people, technology, compliance, and controls. The Board of Directors and senior management team are committed to this transformation and believe that it will be of significant benefit to the Company and its stakeholders.

Capital Expenditures

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	2017	2016	2017	2016
Maintenance and development drilling	$ 69,666	$ 51,501	$ 169,534	$ 83,989
Facilities and infrastructure	20,262	7,895	29,858	32,412
Exploration activities (1)	19,231	2,551	29,019	34,558
Administrative assets and prepaid expenses	1,272	460	7,034	7,673
Other projects	782	2,300	956	10,503
Total capital expenditures	**$ 111,213**	**$ 64,707**	**$ 236,401**	**$ 169,135**

1. Includes E&E revenues and costs.

During 2017, capital expenditures totalled $236.4 million compared with $169.1 million in 2016. During 2017, a total of $169.5 million was invested in the expansion and construction of production infrastructure, primarily in the Guatiquia, Quifa, Cubiro, Mapache and Avispa fields, $29.9 million went into facilities, $29.0 million went into exploration activities and $8.0 million was invested in other projects.

Assets Held for Sale (Executed/Closing) Summary

During the fourth quarter of 2017, the Company continued with its corporate strategy to monetize non-core assets. On October 25, 2017, the Company entered into an agreement to sell PEL for proceeds of $56.0 million, and accordingly, classified the assets and associated liabilities as held-for-sale as at December 31, 2017, and recognized a loss of $1.0 million upon measurement at the lower of carrying value and fair value less costs of disposal. On February 9, 2018, the Company received $20.0 million as an advance on the purchase price. The advance will be used to fund, in part, the first payment under the Pacific Midstream Acquisition Agreement, and is therefore held in an escrow account pursuant to such agreement.

Additionally, on October 20, 2017, and after receiving ANH approval, the amendments of Putumayo 9, Tacacho and Terecay Blocks were signed, and on November 10, 2017, the amendment of Mecaya Block was executed, formalizing the assignment of the Company's interest in such blocks to Amerisur Exploración Colombia, including the return and cancellation of all bank guarantees required by the ANH.

On December 5, 2017, the approvals for the transfer of interests in the Papua New Guinea Blocks were obtained, and proceeds of $57.0 million were received by the Company on February 20, 2018.

Below is a summary of certain non-core asset sales and exploration and production blocks divestments executed during 2017; many of which are pending final government approval.

		(in millions of US$)			
Assets Divested	Country	Net Cash Proceeds	Exploration Obligations (1)	SBLC/ Collateral (2)	Status
Major lands	Colombia	6.2	—	—	Under negotiation
Putumayo Basin	Colombia	4.9	26.3	2.9	Finalized
Casanare Este	Colombia	2.0	7.9	0.8	Pending government approval
Sinu San Jacinto Norte 7 Block	Colombia	Nominal	7.8	2.5	Pending final amendment signature by the buyer
Cerrito	Colombia	0.1	—	—	Finalized
Exploration blocks	Papua New Guinea	57.0	—	—	Finalized
PEL	Colombia	56.0	—	—	Agreement signed. Subject to closing.
		126.2	**42.0**	**6.2**	

1. Estimated.
2. Standby Letter of Credit.

Contract Renegotiations, Liability Reductions and Acquisitions

- On October 13, 2017, the Company entered a share sale agreement with the IFC Parties pursuant to which the Company agreed to acquire the outstanding 36.36% of common shares in PML for the aggregate purchase price of $225 million, to be paid in installments over a 36-month period, including accrued interest on unpaid amounts. The completion of the transaction is subject to obtaining modifications to certain take-or-pay contracts the Company has in place relating to the Bicentenario pipeline, among other customary conditions prior to closing. Pursuant to the Pacific Midstream Acquisition Agreement, should the transaction fail to close by October 13, 2018 as a result of the Company failing to satisfy certain conditions precedent, the Company will be required to pay a breakage fee in the aggregate amount of $5.0 million to the IFC Parties. The transaction is also subject to consent from the holders of the Company's Senior Secured Notes and lenders under the Secured LC Agreement. Following the closing of this transaction, PML will be a 100% consolidated entity of the Company.
- On October 25, 2017, the Company entered into an agreement to sell its interest in PEL to an affiliate of Electricas de Medellin-Ingeniería y Servicios S.A.S. Consideration for the sale will be $56.0 million in cash, of which $50.0 million will be used as the first payment to the IFC Parties in connection with the purchase of the IFC Parties' common shares in PML. On February 9, 2018, the Company received $20.0 million as an advance on the purchase price classified as restricted cash; however, neither the shares nor the promissory note will be transferred until closing.
- On October 3, 2017, the ANH approved the transfer of the Sinu San Jacinto Norte 7 Block to CNE Oil in consideration for assuming all contractual exploration obligations of the Company, which total $7.8 million. The transfer of the participating interest is subject to execution of an amendment of the Sinu San Jacinto Norte 7 agreement.
- On November 15, 2017, the ANH accepted the proposal for the termination of the Sinu San Jacinto Norte 3 licence by mutual consent of the parties without the payment of penalties and/or damages. The liquidation process of the contract with the ANH was initiated during the fourth quarter.
- On January 2, 2018, the ANH approved the transfer of $6.0 million in exploratory investment commitments from the La Creciente Block to the Guatiquia Block. This transfer was requested in accordance with ANH's Acuerdo 2, 2015, which was adopted to help mitigate the adverse effects of the fall of international oil prices by allowing companies to transfer certain exploratory obligations from non-prospective blocks to other prospective blocks.
- On March 13, 2017, the Company entered into a binding term sheet with Maple Gas Corporation del Peru SRL pursuant to which the Company agreed to transfer its participating interest in Lot 126 located in Peru for $0.2 million. However, on November 27, 2017, Perupetro denied the transfer in accordance with the terms and conditions of the term sheet. On December 18, 2017, Perupetro and the Company agreed to terminate the licence agreement relating to Lot 126. As a consequence of relinquishing its interest in the block without fulfilling the agreed upon commitments, the Company paid Perupetro the aggregate amount of $2.8 million and corresponding abandonment costs of $10.3 million.

Restructuring Transaction

On April 19, 2016, the Company, with the support of certain holders of its previous senior notes and lenders under its credit facilities, which totalled $5.3 billion, entered into an agreement with The Catalyst Capital Group Inc. ("**Catalyst**") with respect to implementing a comprehensive financial restructuring transaction ("**Restructuring Transaction**"). Pursuant to the terms of the Restructuring Transaction, the claims of certain creditors ("**Affected Creditors**") were compromised in exchange for common shares in the Company. On November 2, 2016, the Company successfully implemented the Restructuring Transaction in accordance with its plan of compromise and arrangement that was approved by both the Affected Creditors and the Ontario Superior Court of Justice (Commercial List). The Restructuring Transaction substantially changed the capital structure of the Company, reducing financial debt to $250 million, represented by five year Senior Secured Notes. As well, a Secured LC Agreement was established, which at the time of the implementation of the Restructuring Transaction totalled $115.5 million. After completion of the Restructuring Transaction, the shareholders of the Company comprised the Affected Creditors with approximately 69.2% and Catalyst with approximately 30.8% of the common shares.

Additional information is included in Note 1: "Corporate Information" of the Company's audited annual financial statements as at December 31, 2016.

Selected Quarterly Information

	2017				2016			
(in thousands of US$ except as noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial and operational results:								
Net production after royalties [1]	64,445	71,068	72,370	72,524	69,432	75,096	127,951	142,337
Oil production (boe/d)	59,131	65,641	66,448	66,035	62,229	67,128	118,526	131,856
Natural gas production (mcf/d)	30,290	30,934	33,755	36,987	41,057	45,418	53,723	59,742
Oil and natural gas sales (boe/d)	65,481	63,162	64,908	70,452	67,470	81,877	109,736	120,220
Combined price (including hedging losses/gains)	53.26	47.86	46.28	45.95	41.92	40.83	37.60	41.67
Realized oil and gas price	56.19	47.55	45.71	47.34	43.44	40.83	37.60	26.90
Realized hedging (loss) gain	(2.93)	0.31	0.57	(1.39)	(1.52)	—	—	14.77
Brent ($/bbl)	61.54	52.17	50.79	54.57	51.06	46.99	47.03	35.21
Operating cost ($/boe)	(29.65)	(24.32)	(25.97)	(25.36)	(27.40)	(24.06)	(20.30)	(21.13)
Operating Netback ($/boe) [2]	23.61	23.54	20.31	20.59	14.52	16.77	17.30	20.54
Adjusted Netback ($/boe) [2]	21.83	20.68	19.13	18.49	13.89	12.91	17.25	19.81
Adjusted FFO Netback ($/boe) [2]	15.13	12.64	11.76	13.38	2.48	2.55	9.17	18.93
Total sales ($)	335,346	307,080	299,452	316,638	269,772	308,705	376,403	456,831
Net (loss) income attributable to equity holders of the Company	(32,544)	(141,115)	(51,542)	8,498	4,025,194	(557,068)	(118,654)	(900,949)
Per share – basic [3]	(0.65)	(2.82)	(1.03)	0.17	80.50	(176,835.08)	(37,665.40)	(285,996.31)
Per share – diluted [3]	(0.65)	(2.82)	(1.03)	0.17	80.47	(176,835.08)	(37,665.40)	(285,996.31)
Operating EBITDA ($) [2]	105,010	105,885	86,857	92,442	44,275	89,846	120,452	190,064
Adjusted EBITDA ($) [2]	1,999	44,203	87,389	115,058	(1,967)	37,689	126,083	91,814
Adjusted FFO ($) [2]	94,695	47,889	46,151	78,760	8,256	43,036	44,314	161,366
Capital expenditures ($) [4]	111,213	48,563	37,826	38,799	64,707	33,631	50,044	20,755
Total assets (end of period) ($)	2,579,651	2,546,631	2,621,871	2,772,423	2,741,719	2,403,602	2,990,699	2,687,858

1. *Net production after royalties represents the Company's working interest volumes, net of royalties and internal consumption.*
2. *Refer to Non-IFRS Measures on page 20.*
3. *Both basic and diluted weighted average numbers of common shares for the year ended December 31, 2017, were 50,005,832 (December 31, 2016: 50,002,363 and 50,018,997, respectively).*
4. *Capital expenditures includes E&E revenues for the year ended December 31, 2017 and 2016 of $23.1 million and $13.7 million, respectively.*

Over the past eight quarters, the Company's oil and gas sales have fluctuated due to changes in production, movement in the Brent benchmark prices and fluctuations in crude oil price differentials. The Company's production has fluctuated due the expiration of the Rubiales-Piriri contracts in June 2016 and natural production declines in other fields. Net income has fluctuated primarily due to changes in unrealized risk management gains and losses, which fluctuate with the changes in forward market prices, net impairments of oil and gas impairments mainly recorded in the third quarter of 2017 and first quarter of 2016 and net reversals of impairments recorded in the fourth quarter of 2016, lower DD&A during 2017 due to lower depletable base after the impairments along with significant reductions in expenses relating to financing and administrative costs as the Company exited the restructuring process in November 2016.

For additional information, please refer to “Financial and Operating Results” for a detailed discussion on variations during the comparative quarters and to the Company’s previously issued annual and interim management discussion & analysis for further information regarding changes in prior quarters.

Selected Annual Information

	As at and for the year ended December 31		
(in thousands of US$, except as noted)	2017	2016	2015
Total sales	1,258,516	1,411,711	2,824,546
Net (loss) income ($) [1]	(216,703)	2,448,523	(5,461,859)
Per share – basic ($/share) [2]	(4.33)	48.97	(1,733,923)
Per share – diluted ($/share) [2]	(4.33)	48.95	(1,733,923)
Cash and cash equivalents unrestricted	511,685	389,099	342,660
Total assets	2,579,651	2,741,719	3,986,121
Total non-current liabilities	501,902	515,027	236,408
Total liabilities	1,183,270	1,140,684	6,976,352

1. *Net (loss) income attributable to equity holders of the Company.*
2. *Both basic and diluted weighted average numbers of common shares for the year ended December 31, 2017, were 50,005,832 (December 31, 2016: 50,002,363 and 50,018,997, respectively).*

Total sales decreased to $1.26 billion in 2017 from $1.41 billion in 2016 and $2.82 billion in 2015. The decreases were mainly due to the expiration of the Rubiales-Piriri contracts and $173 million lower realized gains from oil price risk management activities compared with 2016. Total oil and gas sales volumes (including trading) for 2017 averaged 65,980 boe/d, 59% lower than the 159,113 boe/d in 2015, mainly due to the expiration of the Rubiales-Piriri contracts in June 2016 and the lower production in other fields. Net Income for 2016 was $2.45 billion, substantially higher than 2015 and 2017, largely due to non-cash items and one-time items, including the recognition of a net gain of $3.62 billion on the cancellation of the debt held by the Affected Creditors and $154.9 million in costs related to the Restructuring Transaction.

Total assets decreased from 2015 to 2017, as a result of the change in the Company’s corporate strategy from developing through acquisitions to developing through optimizing current assets and monetizing non-core assets through divestment, and additional impairment charges on D&P properties and infrastructure assets. Over the past two years, the Company has continued to build cash, and the balance sheet remains strong at the end of the fourth quarter of 2017, with a cash position (including unrestricted cash equivalents) of $511.7 million. The Company recorded net impairment charges of $477.0 million for 2016, which included impairment losses of $1,113.6 million during the first three quarters of 2016 and a reversal of impairment of $636.6 million in the fourth quarter of 2016. Impairment tests were performed at the end of 2016 based on the reserves certified by external evaluators as at December 31, 2016.

Long-term liabilities decreased significantly year-over-year, primarily due to the restructuring of loans and borrowings pursuant to the Restructuring Transaction.

Non-IFRS Measures

This report contains the following financial terms that are not considered in IFRS: Operating and Adjusted EBITDA, Operating Netback, Adjusted Netback, Adjusted FFO Netback, and Adjusted FFO. These non-IFRS measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. These non-IFRS measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These financial measures are included because management uses this information to analyze operating performance and liquidity. These measures are different from those measures disclosed before the third quarter of 2017, reflecting the Company’s new strategic focus on operational efficiency and capital discipline.

Operating and Adjusted EBITDA

Management believes that EBITDA is a common measure used to assess profitability before the impact of different financing methods, income taxes, depreciation and impairment of capital assets, and amortization of intangible assets.

- Operating EBITDA represents the operating results of the Company’s primary business, excluding the effects of capital structure, other investments (infrastructure assets), non-cash items that depend on accounting policy choices, and one-time items that are not expected to recur.
- Adjusted EBITDA excludes items of a non-recurring nature (one-time items) or items that could make the period-over-period comparison of results from operations less meaningful, but includes results from the Company’s other investments (infrastructure assets).

A reconciliation of Operating and Adjusted EBITDA to net (loss) income is as follows:

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	2017	2016	2017	2016
Net (loss) income [(1)]	**$ (32,544)**	**$ 4,025,194**	**$ (216,703)**	**$ 2,448,523**
Adjustments				
Income tax expense (recovery)	(10,438)	(2,778)	15,265	36,175
Depletion, depreciation and amortization	95,062	85,700	382,246	575,985
Impairment and exploration expenses	36,468	(636,594)	123,180	477,005
Finance costs	5,478	66,497	24,168	191,245
Net gain on restructuring	—	(3,620,481)	—	(3,620,481)
Restructuring and severance costs	2,436	55,034	12,617	154,855
Reversal of provision related to high-price clause	(99,622)	—	(99,622)	—
Equity tax	—	—	11,694	26,901
Other expense/(income)	4,786	15,661	5,425	(25,967)
Foreign exchange unrealized loss (gain)	373	9,800	(9,621)	(10,622)
Adjusted EBITDA	**1,999**	**(1,967)**	**248,649**	**253,619**
Loss on valuation of unrealized risk management activities contracts	80,774	13,471	71,762	139,457
Share of (gain) loss of equity-accounted investees	(14,809)	4,253	(76,186)	(62,840)
Gain attributable to non-controlling interest	7,172	5,085	26,788	15,288
Share based compensation loss (gain)	2,119	728	2,605	(7,775)
Foreign exchange realized loss	3,099	4,057	7,745	1,759
Fees paid on suspended pipeline capacity	24,656	18,648	108,831	105,129
Operating EBITDA	**105,010**	**44,275**	**390,194**	**444,637**

1. Net (loss) income 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 gas industry to analyze financial and operating performance expressed as profit per barrel.

- Operating Netback represents realized price per barrel plus realized gain or loss on financial derivatives, less production costs, PAP and royalties paid in cash, and transportation and dilution costs - and shows how efficient the Company is at extracting and selling its product.
- Adjusted Netback represents Operating Netback plus the results from corporate investments such as our pipeline investments that are in addition to oil and gas production and the take-or-pay tariffs paid on disrupted pipelines.
- 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 (mainly includes: dividends from associates, Frontera's share of income from associates, income tax, equity tax paid, realized foreign exchange, inventory fluctuations, overlift/settlement and uses of asset retirement obligations).

The third quarter of 2017 marked the first time the Company disclosed Adjusted FFO and Adjusted FFO Netback, providing stakeholders with greater insight given the increasing significance of these metrics to evaluate operational results. The Company changed from Cash Netback to Adjusted FFO Netback, as the latter provides stakeholders with greater insight into the Company's ability to generate funds from continuing operations.

Refer to "Netbacks" on page 10.

Adjusted Funds Flow from Operations

Adjusted FFO is a non-IFRS financial measure that adjusts an IFRS measure, cash flow 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 excludes asset retirement obligations settlements, one-time expenses for the Company not related to the ongoing operations such as restructuring and severance costs, and loss (gain) from past assets.

	Three Months Ended December 31		Year Ended December 31	
(in thousands of US$)	**2017**	**2016**	**2017**	**2016**
Net cash provided (used) by operating activities	166,750	(63,227)	356,037	(119,677)
Changes in non-cash working capital	25,458	16,310	(2,415)	144,347
Deferred revenue net proceeds	—	—	—	75,000
Restructuring and severance costs	2,436	55,034	12,617	154,855
Settlement of asset retirement obligations	367	139	2,214	2,447
Loss (gain) from past assets and provisions	(100,316)	—	(100,958)	—
Adjusted FFO	**94,695**	**8,256**	**267,495**	**256,972**

6. PRINCIPAL PROPERTIES

	Working Interest	Operated	Gross Acres	Net Acres
Colombia Central				
Quifa	60.00%	Operated	265,954	159,572
Guatiquia	100.00%	Operated	9,274	9,274
Cubiro	100.00%	Operated	44,360	44,360
Cravo Viejo	100.00%	Operated	35,429	35,429
Casimena	100.00%	Operated	6,850	6,850
Arrendajo	97.50%	Operated	33,280	32,448
Neiva	55.60%	Non-operated	2,395	1,332
Corcel	100.00%	Operated	25,141	25,141
Cachicamo	100.00%	Operated	28,471	28,471
Canaguaro	87.50%	Operated	6,289	5,503
Dindal	45.00%	Operated	32,400	14,677
Rio Seco	45.00%	Operated	25,267	11,370
Sabanero	100.00%	Operated	67,896	67,896
Llanos 7	100.00%	Operated	152,674	152,674
Llanos 55	100.00%	Operated	101,466	101,466
Llanos 83	100.00%	Operated	35,755	35,755
Llanos 25	100.00%	Operated	169,805	169,805
Casanare Este (1)	100.00%	Operated	18,476	18,476
Rio Ariari	100.00%	Operated	307,036	307,036
Mapache	100.00%	Operated	57,904	57,904
CPE-6	100.00%	Operated	593,018	593,018
Abanico	25.00%	Operated	62,560	15,640
Buganvilles	49.00%	Operated	77,754	38,100
Cordillera-24	100.00%	Operated	619,817	619,817
Cordillera-15 (2)	50.00%	Non-operated	141,308	70,654
Muisca (2)	50.00%	Non-operated	585,126	292,563
Colombia North				
La Creciente	100.00%	Operated	26,653	26,653
Guama	100.00%	Operated	70,995	70,995
SSJN-7 (3)	50.00%	Operated	668,919	334,460
CR-1	60.00%	Operated	307,384	184,431
Colombia South				
Orito	79.00%	Non-operated	42,492	33,569
Caguan-5	50.00%	Operated	919,321	459,661
Caguan-6	60.00%	Operated	119,048	71,429
Portofino	40.00%	Non-operated	258,676	103,470
Tinigua	50.00%	Non-operated	105,467	52,734
Peru				
Block Z1	49.00%	Non-operated	554,443	271,677
Lot 116 (4)	50.00%	Operated	1,628,126	814,063
Lot 192 (5)	N/A	Operated	1,266,037	1,266,037

1. *Casanare Este Block held for sale to Gold Oil PLC Sucursal Colombia, subject to ANH approval.*
2. *Includes investment in Maurel & Prom Colombia B.V. fields.*
3. *SSJN-7 Block held for sale to CNE Oil & Gas S.A.S., a subsidiary of Canacol Energy Ltd. ("**CNE Oil**"); the ANH has approved the assignment, pending execution of the amendment.*
4. *The Company has entered into a purchase and sale agreement and trust agreement with Les Etablissements Maurel & Prom, Maurel & Prom Colombia B.V. and M&P Peru Holdings S.A.S., pursuant to which the parties agreed to, among other things, the transfer of all the participating interest in Lot 116 to the Company, which is still pending regulatory approval from the Government of Peru.*
5. *The Company does not hold a working interest in Block 192, as the Company had entered into a service contract for the operation of the block and not a licence contract. The Company receives payment in-kind from Perupetro, which ranges from 44% to 84% of production.*

7. LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2017, the Company had cash and cash equivalents of $511.7 million, an increase of $122.6 million from the balance as at December 31, 2016. This increase is primarily due to net operating cash inflows of $356.0 million and the receipt of gross cash proceeds of $37.1 million related to the sale of assets held for sale, offset by net capital expenditures of $236.4 million. As at December 31, 2017, working capital was $210.4 million, an increase of $4.8 million compared with December 31, 2016, mainly due to the Company's ability to generate operating cash flow in excess of capital expenditures for the year ended December 31, 2017. In addition, the Company has benefited from its cash investments, most of which are held in high-interest savings accounts, term deposits and Colombian mutual funds with high credit ratings and short-term liquidity, in accordance with the Company's investment policy and the restrictions in our Indenture (defined below) covenants.

Financial Position

Upon completion of the Restructuring Transaction and as at December 31, 2017, the Company's only long-term borrowing consisted of Senior Secured Notes due in 2021, bearing interest at 10% per annum.

The Senior Secured Notes are secured on a first lien basis through a package of liens, pledges, mortgages and charges that extend directly or indirectly to most of the assets of the Company and its subsidiaries. All significant bank accounts are subject to certain springing blocked account agreements and may be brought under the control of the creditors in the event of default of the Company under the Indenture or the Secured LC Agreement as defined below, which share on a first and second lien basis the same pool of security.

Covenant/Limitation on Indebtedness

Under the Indenture for the Senior Secured Notes due in 2021 (the "**Indenture**"), the Company may not incur, with some exceptions, directly or indirectly, any additional indebtedness prior to November 2, 2018. Subsequent to November 2, 2018, and after giving effect to certain conditions provided under the Indenture, the Company may incur additional indebtedness provided that the Company complies with the following financial covenants:

Covenant	Ratio
Consolidated Debt to Consolidated Adjusted EBITDA (1)	< 2.5 : 1.0
Consolidated Fixed Charge (2)	> 3.25 : 1.0

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

2. *Consolidated Fixed Charge Ratio means the Consolidated Adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period.*

Other covenants under the Indenture limit, with some exceptions, the Company's ability to sell assets, incur liens, declare dividends and enter into lease-back transactions. As at December 31, 2017, the Company is in compliance with such covenants.

Letters of Credit

The Company has various guarantees in place in the normal course of business. As at December 31, 2017, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of $86.3 million.

The Company entered a stand-by letter of credit revolving credit agreement on June 22, 2016, which was amended and restated on November 2, 2016 (the "**Secured LC Agreement**") with a maturity date of June 22, 2018. As at December 31, 2017, outstanding letters of credit under the Secured LC Agreement totalled $82.3 million compared to $111.7 million as of December 31, 2016.

The Company pays a credit facility fee of 5% per annum on the issued and maintained amounts, and will pay 8% per annum on amounts drawn under any issued letters of credit. If any event of default exists, the applicable rate will increase by an additional 2% per annum until such default is cured.

The Secured LC Agreement contains covenants and events of default similar to those in the Indenture. As of the date hereof, the Company is in compliance with such covenants.

In light of the significant financial restrictions imposed by the Indenture, there can be no assurances that the Company will be successful in its efforts to obtain replacement letters of credit on terms satisfactory to the Company.

Credit Rating Table

	Fitch Ratings	S&P Ratings
Corporate credit rating	N/A	BB-
Long-term foreign currency IDRs	B+	N/A
Long-term local currency IDRs	B+	N/A
Senior Secured Notes	BB-/RR3	BB-
Outlook	Stable	Stable

Commitments and Contingencies

The Company's commitments as at December 31, 2017, undiscounted and by calendar year, are presented below:

(in thousands of US$)	2018	2019	2020	2021	2022	2023 and Beyond	Total
Financial							
Debt	—	—	—	250,000	—	—	250,000
Finance lease	6,778	6,778	6,797	4,514	—	—	24,867
Transportation commitments							
ODL ship-or-pay agreement	50,034	49,052	30,073	1,144	—	—	130,303
Bicentenario ship-or-pay agreement	138,447	138,447	138,447	138,447	138,447	210,140	902,375
Transportation and processing commitments	233,982	232,575	232,575	232,610	191,712	720,041	1,843,495
Exploration commitments							
Minimum work commitments	126,194	31,413	54,615	27,546	—	—	239,768
Other commitments							
Operating purchases and leases	47,183	5,297	4,982	4,982	4,982	4,281	71,707
Community obligations	8,863	1,099	—	—	—	—	9,962
Total	**611,481**	**464,661**	**467,489**	**659,243**	**335,141**	**934,462**	**3,472,477**

The Company also has various guarantees in place in the normal course of business. As at December 31, 2017, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of $86.3 million compared to $162.8 million in 2016.

OCENSA Pipeline

Minimum credit rating requirement

In Colombia, the Company is participating as a shipper in a project to expand the OCENSA pipeline (Project P-135), which commenced operations in July 2017. As part of the expansion project, the Company, through its Colombian branches, entered into two crude oil transport agreements with OCENSA for future transport capacity. The Company started paying ship-or-pay fees once the expansion project was completed and operational. As part of the expansion project agreements, the Company is required to maintain minimum credit ratings of BB- (Fitch) and Ba3 (Moody's) or to evidence compliance with net assets and working capital tests. The Company met the net assets and working capital tests as at December 31, 2017.

Transporte Incorporado – minimum credit rating requirement and guarantees

Pursuant to an assignment agreement with Transporte Incorporado, an entity owned by the Darby Private Equity Fund, the Company is entitled to Transporte Incorporado's transport capacity rights through the OCENSA pipeline at a set monthly premium through March 1, 2024. As part of this assignment agreement, the Company is required to maintain a minimum credit rating of B1 as determined by Moody's and B+ by both Standard and Poor's and Fitch. In 2015, ratings downgrades resulted in the triggering of an early-termination right in favour of Transporte Incorporado, that requires the Company to immediately pay an early-termination payment set forth in the assignment agreement upon receiving notice from Transporte Incorporado. The Company has received a waiver from Transporte Incorporado of its right to early-terminate for a period of time, which has been extended several times and is currently set to expire on March 31, 2019.

Transporte Incorporado maintains a unilateral put right under the assignment agreement that is available from April 2019 until March 2020. If the put right is exercised, the assignment agreement would be terminated, the transport capacity rights would be transferred to the Company and the Company would be required to pay Transporte Incorporado an estimated amount of $47 million at the commencement of the put period or $30 million by the end of the put period.

Under the assignment agreement, the Company also has a call right available from April 2020 until March 2021. If the Company exercises such call right the assignment agreement would be terminated, the transport capacity rights would be transferred to the Company and the Company would be required to pay Transporte Incorporado an estimated amount of $69 million at the commencement of the call period or $45 million by the end of the call period.

Transportation tariffs and monetary conditions

On April 25, 2017, the Company commenced arbitration proceedings against OCENSA with the Centre for Arbitration and Conciliation of the Bogota Chamber of Commerce. The proceedings were initiated in relation to the standard transportation tariff and monetary conditions included in certain contracts entered into with OCENSA in 2014 relating to crude transport services. These contracts were entered into in connection with the expansion of the OCENSA Pipeline. On October 30, 2017, OCENSA filed a counterclaim against the Company. On February 6, 2018, the Company and OCENSA entered into an agreement of intent outlining a resolution to the claim. On February 19, 2018, the Company and OCENSA amended their respective claims. The Company and OCENSA are in the process of submitting their settlement agreement to the arbitrators for approval. Upon approval of the terms by the arbitration tribunal, the parties will execute the corresponding amendments to the contracts to include the revised transport tariff and monetary conditions. Without approval from the arbitrators, the arbitration proceedings will continue with it being understood that the parties have not waived any of their rights or claims.

Other Guarantees and Pledges

On December 14, 2016, the Company granted a security interest in favour of Talisman Colombia Oil & Gas Ltd. (**"TCOG"**) for 50% of the production (after royalties, ANH economic rights and other applicable discounts) of the CPE-6 Block in Colombia up to $48.0 million. This arose from the Company's acquisition of TCOG's 50% working interest in the CPE-6 Block.

On October 4, 2013, the Company's subsidiary Pacinfra Holding Ltd. ("**Pacinfra Holding**"), Pacific Infrastructure Ventures, Inc. ("**PII**"), Sociedad Portuaria Puerto Bahia S.A. ("**Puerto Bahía**") and Wilmington Trust, National Association (as Collateral and Administrative Agent), entered into an equity contribution agreement, pursuant to which Pacinfra Holding Ltd. and PII agreed to jointly and severally cause equity contributions (via debt or equity, at the option of the Company) 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. PII's other minority shareholder, International Finance Corporation, has the contractual right to subscribe, at its discretion, up to 50% of the Company's obligations under the agreement. On February 27, 2018, Wilmington Trust, National Association issued a deficiency notice to Pacinfra Holding Ltd. and PII requesting both companies fund, or cause to be funded, a total amount of $26.9 million to Puerto Bahia.

PAP Disagreement with the ANH

The Company has certain exploration and production contracts acquired through business acquisitions where outstanding disagreements with the ANH existed relating to the interpretation of the PAP clause. These contracts require high-price participation payments be made to the ANH for each designated exploitation area within a block under contract, which has cumulatively produced five million or more barrels of oil. The disagreement involves whether the cumulative production amounts in an exploitation area should be calculated individually (as each exploitation area represents independent reservoirs) or combined with other exploration areas within the same block for the purpose of determining the five-million-barrel threshold. The ANH has interpreted that the high-price participation should be calculated on a combined basis versus the Company's interpretation of utilizing the individual calculation.

The Company and the ANH are currently in discussions to further understand the differences in interpretation of these exploration and production contracts (excluding the Corcel Block, discussed below). However, in accordance with IFRS 3 *Business Combinations*, under business acquisitions accounting the Company was required to recognize a provision for such contingencies at the date of acquisition, even though the Company believed the disagreement would be resolved in its favour. The Company does not disclose the amount recognized as required by paragraphs 84 and 85 of IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* ("**IAS 37**"), on the grounds that this would be prejudicial to the outcome of potential disputes.

Reversal of provision related to high-price clause - the Corcel Block

The Corcel Block, which was acquired as part of the Petrominerales acquisition in 2013, is the only block for which a binding arbitration process was initiated, and in which the ANH claimed in 2013 that it was owed $167.2 million plus interest as at December 2012. On December 6, 2017, an arbitration panel delivered a ruling in favour of the Company's interpretation. As a result, given the settlement of the matter by the competent judge (the arbitration panel), the contingent liability previously recorded for the Corcel Block was reversed and a recovery of $99.6 million was recognized in the Consolidated Statements of (Loss) Income during the year ended December 31, 2017.

On December 14, 2017, the ANH filed a request for annulment of the arbitration panel's decision with the Consejo de Estado (Colombia's highest administrative court), and the matter is currently being reviewed by this Court. Subsequent actions, including the annulment request, was assessed under IAS 37, and no provision was recognized as at December 31, 2017 given the initial stages of this new request and the existing ruling from the binding arbitration process in favour of the Company.

Tax Review in Colombia

The Colombian tax authority, the DIAN, is reviewing certain income tax deductions with respect to the special tax benefit for qualifying petroleum assets as well as other exploration expenditures. As at December 31, 2017, the DIAN has reassessed $85.8 million of tax owing, including estimated interest and penalties, with respect to the denied deductions (2016: $56.6 million).

The Company believes that disagreements with the DIAN related to the denied income tax deductions will be resolved in favour of the Company. No provision with respect to income tax deductions under dispute has been recognized as at December 31, 2017 and 2016.

Tax Review in Peru

The Peruvian tax authority, the SUNAT, completed a tax audit for the taxation year 2013, which resulted in the denial of certain expenses of approximately $22.4 million, including estimated interest and penalties, claimed by Pacific Off Shore Peru S.R.L. as part of the carry agreement with BPZ Exploration & Production with respect to the joint investment in Block Z-1.

The Company believes that that the disagreements with the SUNAT related to the denial of expenses will be resolved in favour of the Company. No provision with respect to the expenses under dispute has been recognized as at December 31, 2017 and 2016.

8. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 27, 2018:

	Number
Common shares	50,005,832
Deferred share units ("DSUs") [1]	50,011
Restricted share units ("RSUs") [2]	360,710

1. *DSUs represent a future right to receive Common Shares (or the cash equivalent) at the time of the holder's retirement, death or the holder otherwise ceasing to provide services to the Company. Each DSU awarded by the Company is initially equal to 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.*
2. *RSUs are granted with vesting conditions (typically based on continued service or achievement of personal or corporate objectives). The value of RSUs increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of a 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.

9. RELATED-PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances, outstanding (before impairments) and commitments with related parties, as at and for the years ended December 31, 2017 and December 31, 2016:

(in thousands of US$)		Accounts Receivable	Accounts Payable	Commitments	Cash Advance	Loans Receivable(2)	Interest Receivable(2)	Convertible Debentures(2)
Oleoducto de los Llanos (ODL)	2017	421	231	130,303	—	—	—	—
	2016	639	342	176,442	—	—	—	—
Bicentenario	2017	12,660	469	902,375	87,278	—	—	—
	2016	13,400	433	1,164,251	87,278	—	—	—
Pacific Infrastructure Ventures Inc. (PII) – Sociedad Portuaria Puerto Bahia S.A.	2017	5,926	1,598	158,179	17,741	76,552	26,331	—
	2016	828	905	199,859	17,741	74,279	18,097	—
Interamerican Energy – Consorcio Genser Power – Proelectrica – Termomorichal	2017	145	72	—	—	2,224	362	—
	2016	174	600	—	—	2,224	24	—
CGX Energy Inc. (CGX)	2017	120	—	—	—	14,622	1,516	1,500
	2016	—	—	—	—	10,000	800	1,500
Paye Foundation (1)	2016	4	1,737	—	—	—	—	—

(in thousands of US$)		Sales	Purchases / Services	Interest Income(2)
Oleoducto de los Llanos (ODL)	2017	3,973	50,135	—
	2016	4,224	89,513	—
Bicentenario	2017	—	127,333	—
	2016	—	168,813	—
Pacific Infrastructure Ventures Inc. (PII) – Sociedad Portuaria Puerto Bahia S.A.	2017	—	35,600	8,234
	2016	—	36,687	9,417
Interamerican Energy – Consorcio Genser Power – Proelectrica – Termomorichal	2017	407	24	338
	2016	8,720	17,200	24
CGX Energy Inc. (CGX)	2017	526	—	716
	2016	—	—	470
Paye Foundation (1)	2016	94	4	—

1. The Paye Foundation (formerly Pacific Rubiales Foundation) was in liquidation as at December 31, 2017. The Company established the new Frontera Foundation charity in Colombia in 2017, which is a consolidated subsidiary of the Company.

2. Amounts presented based on contractual payment obligations, prior to impairments.

The following sets out the details of the Company's related party transactions as summarized in the tables above:

- **Oleoducto de los Llanos (**"**ODL**"**)** – Services expense incurred related to take-or-pay contracts the Company has with ODL for the transportation of crude oil from the Company's fields to Colombia's oil transportation system for a total commitment of $130.3 million from 2018 to 2021. The Company also earned revenue with respect to power transmission sales to ODL.
- **Bicentenario** – Services expense incurred relate to ship-or-pay contracts the Company has with Bicentenario for transportation of crude oil from the Company's fields to Colombia's oil transportation system for a total commitment of $0.9 billion from 2018 to 2025. The Bicentenario pipeline has experienced periodic suspensions following security-related disruptions. The Company also has advances with Bicentenario as a prepayment of transport tariff which are to be amortized against future barrels transported above the Company's contract capacity, and trade receivables and payables related to transportation taxes.
- **PII** – The Company has loans receivable from PII that are guaranteed by PII's pipeline project and bear interest that ranges from LIBOR 6M + 3% to 10% per year. The Company also incurred services expense related to take-or-pay contracts for the transfer, loading, and unloading of hydrocarbons at its port facilities, for a total commitment of $158.2 million from 2018 to 2021, for which the Company recognizes associated purchases and service expenses and related payable balances. The Company also has a receivables balance in 2017 associated with fuel tanks under lease by the Company, that was subleased by PII to another operator.

- **CGX Energy Inc. ("CGX")** – The Company has a series of loans with CGX. On April 26, 2017, the Company entered into a secured bridge loan facility with CGX. The principal amount of up to $3.1 million is divided into tranches payable within 12 months of the first draw-down. The Company amended this facility to increase the principal amount from $3.1 million to $4.0 million, as at December 31, 2017, with all other terms unchanged. The loan carries an annual interest rate of 5% and is secured by the assets of CGX. As at December 31, 2017, the Company had advanced $3.7 million under this facility. No impairment indicators were identified for the bridge loan facility as at December 31, 2017.

  The Company has previously provided CGX with a series of loans and facilities totalling $4.0 million (issued in 2016) and C$7.5 million (issued in 2014), due April 25, 2018. CGX has drawn down $4.0 million and C$7.5 million, respectively, of these loans as at December 31, 2017 (2016: $3 million and C$7.5 million, respectively). The amounts drawn under these loans were fully impaired as at December 31, 2017 and 2016.

  In addition, in November 2015, CGX issued convertible debentures to the Company in an amount of $1.5 million with a conversion price of C$0.335, due April 25, 2018, and as at December 31, 2017, the Company has not converted the debentures.

  The Company also has service arrangements with respect to certain corporate administrative services and technical service support provided for CGX's operations in Guyana.

- **Interamerican Energy Corp ("Interamerican")** – The Company entered into a loan agreement with Interamerican for an amount of $2.2 million bearing an annual interest of 15% on December 13, 2016. The Company also purchases energy supply services from Interamerican, and recognizes gas sales supplied from the La Creciente fields.

- **Dividends** – The Company, as shareholder, received dividends from associate investees ODL and Bicentenario. During the year ended December 31, 2017, PML recognized dividends of $68.6 million (2016: $120.4 million), with $21.7 million distributed to the minority interest in PML (2016: $41.8 million).

The Company's key management personnel include its Board of Directors and the executive officers. Compensation for key management personnel is summarized below:

	As at December 31	
(in thousands of US$)	**2017**	**2016**
Short-term employee benefits	4,184	26,610
Termination benefits	2	20,603
Post-employment pension and medical benefits	—	3,295
Share-based payments	1,643	1,571
Total compensation	**5,829**	**52,079**

10. 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, the 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 also 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 Consolidated Financial Statements and this MD&A. The list above does not contain all of the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risk and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the Company's AIF and Consolidated Financial Statements, copies of which are available at www.sedar.com.

11. ACCOUNTING POLICIES, CRITICAL JUDGMENTS, AND ESTIMATES

The Consolidated 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 3 of the Consolidated 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 3 of the Consolidated Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the Consolidated Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies and 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 3 of the Consolidated Financial Statements.

12. 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 Annual 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 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. Additionally, projections of any evaluation of effectiveness in future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's ICFR as at December 31, 2017, based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, the Company's Chief Executive Officer and its Corporate Finance Director, in the capacity of chief financial officer, concluded that the Company's ICFR were effective as at December 31, 2017.

There have been no changes in the Company's ICFR during the quarter ended December 31, 2017 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 annual 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.

Based on Management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and its Corporate Finance Director, in the capacity of chief financial officer, concluded that the Company's DC&P were effective as at December 31, 2017.

13. 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. For properties in Peru, the Company has expressed boe using the Peruvian conversion standard of 5.626 Mcf: 1 bbl required by Perupetro.

Abbreviations

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

1P	Proved reserves	**Mcf**	Thousand cubic feet
2P	Proved reserves + Probable reserves	**Mbbl**	Thousand barrels
API	American Petroleum Institute - gravity measure of petroleum liquid	**Mbbl/d**	Thousand barrels per day
bbl	Barrels	**Mboe**	Thousand barrels of oil equivalent
bbl/d	Barrels per day	**Mboe/d**	Thousand barrels of oil equivalent per day
boe	Barrels of oil equivalent	**MMbbl**	Million barrels
boe/d	Barrels of oil equivalent per day	**MMbbl/d**	Million barrels of oil per day
D&P	Development and producing	**MMboe**	Million barrels of oil equivalent
CPI	Incremental production contract	**$**	U.S. dollars
E&E	Exploration and evaluation	**$M**	Thousand U.S. dollars