

MANAGEMENT DISCUSSION & ANALYSIS

May 10, 2018
For the three months ended March 31, 2018

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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.

This MD&A is management’s assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying unaudited Interim Condensed Consolidated Financial Statements and related notes for the quarters ended March 31, 2018 and 2017 (“Interim Financial Statements”). The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board, unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These measures are described in greater detail under the heading “Non-IFRS Measures” on page 13.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, the Company has provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts may differ, and these differences may be material. This information, among others, may contain future oriented financial information (“FOFI”) within the meaning of applicable securities laws. The FOFI has been prepared by management to provide an outlook of the Company’s activities and results and may not be appropriate for other purposes. Management believes that the FOFI has been prepared on a reasonable basis, reflecting best estimates and judgments; however, actual results of the Company’s operations and the financial outcome may vary from the amounts set forth herein. Any FOFI speaks only as of the date on which it was made and, except as may be required by applicable securities law, the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or otherwise.

Additional information with respect to the Company, including the Company’s quarterly and annual financial statements and the AIF, has been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com and on the Company’s website at www.fronteraenergy.ca. Information contained in or otherwise accessible through the Company’s website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

1. MESSAGE TO THE SHAREHOLDERS

Firstly, I would like to thank Barry Larson and all our talented people for their help in what has been a seamless transition for me from the Board of Directors to the Chief Executive Officer. This is an exciting time to be at the helm of Frontera as we position the Company for production and reserves growth through a number of initiatives, including exploration and investments in strategic facilities.

In the first quarter of 2018, we took the initial steps to execute these initiatives. In both our heavy and light/medium oil segments, we announced successful exploration wells whose potential reserves will aid us in growing production over the near- and medium-term. In addition, we began the implementation of a strategic water handling facilities expansion project in our heavy oil fields that will enable the Company to increase heavy oil production over current levels by drilling new wells, reactivating shut-in wells, and increasing overall well productivity.

First quarter net production after royalties and internal consumption increased 3% in comparison to the previous quarter as we successfully reactivated fields in Block 192 in Peru. We continue to work to find a long-term solution together with the Peruvian government for the operation of the block. In Quifa, we continue to see improved heavy oil rates and our exploration program in the Guatiquía block has resulted in discoveries which are being brought to production quickly. First quarter oil sales volumes were lower than the previous quarter primarily due to an overlift settlement and a late cargo shipment; the impact of the late cargo shipment will be reversed in the second quarter as the sale of the cargo is recognized.

I am very pleased by the running start we have given ourselves for the year. We are currently drilling the deep Acorazado-1 exploration well in the Colombian foothills - a complex well to drill but one which is targeting a significant volume of hydrocarbons in this productive foothills trend which contains the Cusiana and Cupiagua fields. We also plan to drill the Delfin Sur exploration well in Block Z1 offshore Peru during the third quarter, marking Frontera's first offshore exploration project. While Delfin and Acorazado are significant undertakings, they have the potential to become new core assets for the Company. With a strong balance sheet and proven cash generation capacity, Frontera is well-positioned to continue taking advantage of opportunities like these with the goal of delivering value to our shareholders.

Richard Herbert
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Operating and Financial Summary

		Q1 2018	Q4 2017	Q1 2017
Operational Results				
Net production after royalties ^(1,2)	(boe/d)	66,227	64,445	72,524
Oil production	(bbl/d)	61,352	59,131	66,035
Natural gas production	(Mcf/d)	27,788	30,290	36,987
Combined price (including realized loss on risk management contracts)	(\$/boe)	52.36	53.26	45.95
Realized oil and natural gas and other revenue price	(\$/boe)	61.34	56.19	47.34
Realized loss on risk management contracts	(\$/boe)	(8.98)	(2.93)	(1.39)
Operating cost	(\$/boe)	(27.94)	(29.65)	(25.36)
Production cost	(\$/boe)	(12.47)	(13.13)	(9.43)
High-price participation payments and cash royalties	(\$/boe)	(1.30)	(1.23)	(0.90)
Transportation cost	(\$/boe)	(12.68)	(14.28)	(13.98)
Diluent cost	(\$/boe)	(1.49)	(1.01)	(1.05)
Operating Netback ⁽³⁾	(\$/boe)	24.42	23.61	20.59
Adjusted Netback ⁽³⁾	(\$/boe)	21.35	21.83	18.49
Adjusted FFO Netback ⁽³⁾	(\$/boe)	16.64	15.13	13.38
Capital expenditures ⁽⁴⁾	(\$M)	78,841	111,213	38,799
Financial results				
Total sales	(\$M)	291,861	352,987	325,424
Oil and natural gas sales and other revenue	(\$M)	289,534	338,509	300,153
Sales of oil and natural gas for trading	(\$M)	2,327	14,478	25,271
Total sales after realized loss on risk management contracts	(\$M)	249,468	335,346	316,638
Realized loss on risk management contracts	(\$M)	(42,393)	(17,641)	(8,786)
Net (loss) income ⁽⁵⁾	(\$M)	(3,121)	(32,544)	8,498
Per share – basic and diluted ⁽⁶⁾	\$	(0.06)	(0.65)	0.17
General and administrative	(\$M)	22,053	24,450	27,706
Operating EBITDA ⁽³⁾	(\$M)	85,988	105,010	92,442
Operating EBITDA margin (Operating EBITDA/Total sales after realized loss on risk management contracts)	%	34%	31%	29%
Adjusted EBITDA ⁽³⁾	(\$M)	86,654	1,999	115,058
Adjusted EBITDA margin (Adjusted EBITDA/Total sales after realized loss on risk management contracts)	%	35%	1%	36%
Net cash provided by operating activities	(\$M)	30,265	166,750	66,926
Adjusted FFO ⁽³⁾	(\$M)	34,260	94,695	78,760
Per share – basic ⁽⁶⁾	\$	0.69	1.89	1.58
Per share – diluted ⁽⁶⁾	\$	0.69	1.89	1.57
Total assets	(\$M)	2,664,920	2,579,651	2,772,423
Total cash	(\$M)	695,923	644,086	560,406
Cash and cash equivalents – unrestricted	(\$M)	515,811	511,685	469,974
Restricted cash short and long-term	(\$M)	180,112	132,401	90,432
Total equity ⁽⁷⁾	(\$M)	1,306,964	1,285,750	1,516,983
Debt and obligations under finance lease	(\$M)	268,237	269,229	272,087

1. Net production after royalties represents the Company's working interest volumes, net of royalties and internal consumption.

2. BOE has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.

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

4. Capital expenditures includes revenues from Exploration and Evaluation assets for the three months ended March 31, 2018 and 2017, of \$6.5 million and \$4.8 million, respectively.

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

6. Both basic and diluted weighted average numbers of Common Shares for the three months ended March 31, 2018, were 50,005,832 (March 31, 2017: 50,002,363 and 50,025,751, respectively).

7. Equity attributable to equity holders of the Company.

Performance Highlights

Operational

- In comparison to the previous quarter, the Company increased its average net production by 3%, primarily due to the reactivation of operations at Block 192 in Peru. Average net production after royalties and internal consumption for the period ended March 31, 2018, totalled 66,227 boe/d, a 9% decrease from the average net production of 72,524 boe/d reported for the same period in 2017. The reduction was largely due to limited production from the Cubiro block during the quarter, as a result of a community blockade and the natural decline of the Company's light and medium blocks in Colombia. In addition these factors also partially offset the increase in net production realized quarter-over-quarter.
- Sales volumes for the first quarter of 2018 totalled 52,440 boe/d, significantly lower than the previous quarter's sales volumes of 65,481 boe/d due to overlift settlement and an increase in oil inventories. The oil inventory increase was driven primarily by one oil cargo that was planned for shipment during the first quarter of 2018 but was not shipped until April 2018 and therefore could not be recognized as sales in the first quarter. This cargo contained production from the first quarter of 2018 and will be recognized as sales volumes in the second quarter of 2018.
- Total operating costs (including production, high-price participation payments and cash royalties, transportation and diluent costs) averaged \$27.94/boe in the first quarter of 2018, a 10% increase from the average total operating costs of \$25.36/boe reported for the same period in 2017. The increase in total operating costs is mainly attributable to the increase in unit cost due to lower produced volumes. Operating costs per barrel decreased 6% compared to the fourth quarter of 2017, due to lower production and transportation costs (excluding fees paid on suspended capacity).
- Operating Netback for the quarter was \$24.42/boe, 19% higher than \$20.59/boe in the first quarter of 2017. The increase is mainly attributable to an increase in the market prices for oil. Operating Netback increased by 3% in comparison to \$23.61/boe in the previous quarter mainly due to lower operating costs.
- The Company received cost reimbursement from unused take-or-pay transportation commitments by reversing the direction of the Bicentenario pipeline and transferring capacity to other shippers. The reimbursement totalled \$6.4 million during the quarter, compared to \$nil in the first quarter of 2017 and \$3.7 million in the fourth quarter of 2017.
- During the first quarter of 2018, the Company continued its corporate strategy to position itself for growth in 2018. Capital expenditures were \$78.8 million, 103% higher than \$38.8 million in the first quarter of 2017. The Company had eight rigs operating throughout the first quarter of 2018, with five active in its Quifa heavy oil area, and three on its light oil-focused Guatiquia block. First quarter well activity included drilling 33 development focused wells and three exploration-focused wells. This is below previous expectations of 40 to 50 wells drilled in the first quarter, as activity originally planned at the Cajúa field was deferred until further water handling capacity is added later in the year.

Financial

- Total sales for the three months ended March 31, 2018 were \$291.9 million, a 10% decrease compared to \$325.4 million in the prior year period and a 17% decrease compared to \$353.0 million in the fourth quarter of 2017. The decrease in total sales was primarily due to overlift settlement and an increase in oil inventories during the first quarter of 2018.
- Net loss attributable to equity holders of the Company was \$3.1 million (\$0.06/share) in the first quarter of 2018 compared to Net income attributable to equity holders of the Company of \$8.5 million (\$0.17/share) in the first quarter of 2017. This was primarily the result of net losses on risk management activities totalling \$25.1 million in the quarter compared to a net gain of \$31.4 million in 2017, partially offset by a reduction in operating losses of \$18.8 million.
- Frontera's ending total cash position grew to \$695.9 million as at March 31, 2018, driven by \$30.3 million of cash from operations in the quarter and the receipt of \$20.0 million of gross cash proceeds from the sale of Petroelectrica de los Llanos Ltd. ("PEL") and the receipt of \$57.0 million in cash from the Company's Papua New Guinea assets sale.
- Operating EBITDA was \$86.0 million (\$1.72/share) for the first quarter of 2018, compared to \$92.4 million (\$1.85/share) in the first quarter of 2017 and \$105.0 million (\$2.10/share) in the fourth quarter of 2017. Lower Operating EBITDA was primarily due to a \$42.0 million realized loss on risk management contracts (as compared to \$18.0 million in the fourth quarter of 2017 and \$8.8 million in the first quarter of 2017) and temporarily lower sales volumes due to: (i) an overlift settlement and (ii) a large crude oil inventory buildup mainly driven by one cargo that rolled to April and relatively higher inventory in Peru. The rolled cargo's sales value of \$31.3 million will be recognized in the second quarter. We expect such cargo to generate EBITDA in line with historical EBITDA margins.
- Adjusted fund flow from operations ("**Adjusted FFO**") was \$34.3 million (\$0.69/share) for the three months ended March 31, 2018, a 57% decrease as compared to \$78.8 million (\$1.58/share) in the prior year period and a 64% decrease as compared to \$94.7 million (\$1.89/share) in the fourth quarter of 2017. Lower Adjusted FFO was primarily due to lower Operating EBITDA of \$6.5 million, no dividends received from investments in associates during the first quarter of 2018 (\$27.6 million in the first quarter of 2017 and \$35.5 million in the fourth quarter of 2017), and higher downtime on the Bicentenario pipeline of \$8.8 million.

A reconciliation of Funds Flow from Operations (“FFO”) to Adjusted FFO is as follows:

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Net cash provided by operating activities	30,265	66,926
Changes in non-cash working capital	1,107	5,888
Funds flow from operations	31,372	72,814
Restructuring, severance and other costs	2,838	5,946
Settlement of assets retirement obligations	50	—
Adjusted FFO	34,260	78,760

- Adjusted FFO Netback was \$16.64/boe for the first quarter of 2018, 24% higher than \$13.38/boe reported in the first quarter of 2017. This was primarily due to higher realized prices from the improvement in global oil prices. In comparison to the previous quarter, the Company was able to increase Adjusted FFO Netback by \$1.51/boe as a result of lower operating and general and administrative costs (“G&A”).
- G&A for the quarter was \$22.1 million as compared to \$27.7 million in the first quarter of 2017 and \$24.5 million in the previous quarter, mainly as a result of a continued effort to reduce overhead costs.
- On May 9, 2018, Fitch Ratings Inc. (“Fitch”) reaffirmed its long term Foreign and Local Currency Issuer Default Rating on the Company at “B+”, however, Fitch downgraded the Senior Secured Notes to “B+/RR4” from “BB-/RR3” and removed the Senior Secured Notes from Negative Rating Watch. In April 2018, Fitch had published its revised criteria on evaluating country-specific treatment of recovery ratings. In assessing Colombia under this revised criteria, Fitch had capped the recovery rating of Colombian corporate issuers at “RR4”. As a result, Fitch downgraded the rating of the Company’s Senior Secured Notes to “B+/RR4” to bring the Senior Secured Notes in line with the new capped recovery rating for Colombian corporate issuers. The rating outlook continues to remain stable.

Exploration

- The Alligator-2 exploratory well, on the Guatiquia block, began drilling on January 21, 2018, and reached a true vertical depth of 12,280 feet on February 16, 2018. The well encountered approximately 24 feet of net pay in the Lower Sand-1A formation and was completed in the upper 10 feet of the formation with an electrical submersible pump. The well flow tested for 26 days in March at an average rate of 1,000 bbl/d of 22.5 degree API oil with an average water cut of 40% at a stabilized bottomhole pressure with an 6% drawdown. Since discovery, the well has produced a total of 24,000 bbl.
- The Jaspe-6D exploratory well, on the Quifa block, began drilling on January 26, 2018, and reached a true vertical depth of 3,491 feet on February 5, 2018. The well encountered 33 feet of net pay in the Basal Sand formation and was completed with 10 feet of perforations at the top of the formation with an electrical submersible pump. The well was flow tested for 11 days at an average rate of 187 bbl/d of a 13 API oil with an average water cut of 10% at a stabilized bottomhole flowing pressure with a 14% drawdown. After the production test, the well was shut-in for a 14-day buildup and is currently awaiting approvals for extended testing.
- The Company drilled the Coralillo-1 exploratory well, on the Guatiquia block, on February 15, 2018, and reached a true vertical depth of 11,573 feet on March 27, 2018. The well encountered 13 feet of net pay in the Guadalupe formation and 15 feet of net pay in the Lower Sand-1A formation. The Lower Sand-1A formation has been flow tested for approximately 10 days at an average rate of 1,050 bbl/d of 15.3 degree API oil with an average water cut of 1% at stabilized bottomhole flowing pressure with a 60% drawdown. The well is currently shut-in for a pressure buildup test on the Lower Sand-1A formation. During the testing period, the well produced a total of 9,200 bbl. The well is currently being completed.

3. GUIDANCE

We confirm our Guidance as released March 28, 2018. Based on an average Brent oil price of \$63.00/bbl, we expect to generate Operating EBITDA of \$375.0 to \$425.0 million from net production after royalties of 65,000 boe/d to 70,000 boe/d. Our capital expenditures for the year are expected to be \$450.0 to \$500.0 million.

		2018 Guidance ⁽¹⁾	2018 YTD
Average annual net production after royalties	(boe/d)	65,000 to 70,000	66,227
Production cost	(\$/boe)	12.00 to 14.00	12.47
Transportation cost	(\$/boe)	12.50 to 14.50	12.68
Operating EBITDA	(\$MM)	375 to 425	86
General and administrative expenses	(\$MM)	100 to 110	22
Capital expenditures	(\$MM)	450 to 500	79

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

4. FINANCIAL AND OPERATIONAL RESULTS

Production and Development Review

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

	Average Production (in boe/d)								
	Total field production			Gross share before royalties ⁽¹⁾			Net production after royalties ⁽²⁾		
	Q1 2018	Q4 2017	Q1 2017	Q1 2018	Q4 2017	Q1 2017	Q1 2018	Q4 2017	Q1 2017
Producing fields in Colombia									
Light and medium oil ⁽³⁾	31,143	34,465	39,054	29,370	32,747	37,161	27,125	30,142	34,177
Heavy oil ⁽⁴⁾	47,847	47,798	50,243	28,876	28,972	30,617	25,070	26,451	28,003
Natural gas ⁽⁵⁾	5,566	6,074	7,468	4,875	5,315	6,489	4,875	5,314	6,489
Total production Colombia	84,556	88,337	96,765	63,121	67,034	74,267	57,070	61,907	68,669
Producing fields in Peru									
Light and medium oil ⁽⁶⁾	13,191	4,175	7,805	9,157	2,538	3,855	9,157	2,538	3,855
Total production Peru	13,191	4,175	7,805	9,157	2,538	3,855	9,157	2,538	3,855
Total production Colombia and Peru	97,747	92,512	104,570	72,278	69,572	78,122	66,227	64,445	72,524

1. Includes gross share before royalties, internal consumption and if applicable, high-price participation payments.

2. Includes net production after royalties internal consumption and if applicable high-price participation payments.

3. Includes Cubiro, Cravo Viejo, Casanare Este, Canaguaro, Guatiquia, Casimena, Corcel, CPI Neiva, Cachicamo, Arrendajo, and other producing blocks.

4. Includes Quifa, Cajua, Sabanero, CPE-6, and Rio Ariari blocks.

5. Includes La Creciente and Guama blocks.

6. Includes Block Z1 and Block 192. In addition, production for the first quarter of 2017 includes block 131 which was formally transferred to Cepsa on May 12, 2017.

The Company's daily net production after royalties and internal consumption for the first quarter of 2018 averaged 66,227 boe/d, representing a reduction of 6,297 boe/d from the average net production of 72,524 boe/d reported for the same period in 2017. Average net production increased by 1,782 boe/d, or 3%, in comparison with the fourth quarter of 2017, primarily due to the increase in production from Peru.

Colombia

Light and Medium Oil Production

For the period ended March 31, 2018, daily light and medium oil net production after royalties and internal consumption averaged 27,125 boe/d, 21% lower than the same period in 2017, due to the natural decline of the Company's light and medium oil assets. Net production from the Company's light and medium blocks decreased by 10% in comparison to the previous quarter due to limited production during the quarter from the Cubiro block as a result of a community blockade and from the Guatiquia and Canaguaro blocks due to mechanical well failures. In March 2018, the Company completed a well stimulation at the Guatiquia block that restored daily production back to normal levels.

During the quarter, the Company completed the drilling of two development wells at the Guatiquia block and one development well at the Cubiro block as well as 12 workovers and well services.

Heavy Oil Production

During the first quarter of 2018, daily heavy oil net production after royalties and internal consumption averaged 25,070 boe/d, 10% lower than the same period in 2017. This was largely due to lower results than expected in the Quifa SW drilling campaign combined with the natural decline of the Company's heavy oil assets.

During the quarter, the Company completed the drilling of 30 development wells at the Quifa block and completed 12 workovers and well services.

Natural Gas Production

During the first quarter of 2018, natural gas net production after royalties and internal consumption averaged 4,875 boe/d, which represented a 25% decrease from the same period in 2017, mainly attributable to the natural decline in production at the La Creciente block.

High-Price Participation (“PAP”) Payments

Due to the increase in global oil prices, the Company made certain PAP payments to Ecopetrol S.A. and the Agencia Nacional de Hidrocarburos (the “ANH”) on production at the Quifa, Cubiro, Corcel, Guatiquia and Cravoviejo blocks during the first quarter of 2018. The Company paid approximately 3.16% of its total production in the quarter as PAP payments, higher than 1.76% for the previous quarter and 1.44% in the same period of 2017. The PAP payments are paid in cash for all blocks except for those relating to the Quifa block, which is paid in-kind.

Peru

Light and Medium Oil Production

During the quarter, light and medium oil production after royalties and internal consumption averaged 9,157 boe/d, 138% higher than the same period in 2017 and 261% higher than the previous quarter. The increase in production was mainly attributable to the increase in the total number of days Block 192 was operational during the quarter as compared to the same period in 2017 and the previous quarter.

Net production after royalties reconciled to volume sold

		Q1 2018	Q4 2017	Q1 2017
Net production after royalties	(boe/d)	66,227	64,445	72,524
Oil inventory build ⁽¹⁾	(boe/d)	(7,282)	349	(574)
Overlift (settlement)	(boe/d)	(3,161)	3,032	1,505
Trading and diluent volumes purchased ⁽²⁾	(boe/d)	437	3,924	6,533
E&E assets volumes sold ⁽³⁾	(boe/d)	(1,168)	(1,420)	(1,455)
Trading volumes sold ⁽⁴⁾	(boe/d)	(394)	(3,101)	(5,804)
Other inventory movements ⁽⁵⁾	(boe/d)	(2,219)	(1,748)	(2,277)
Sales volumes	(boe/d)	52,440	65,481	70,452
Oil sales	(boe/d)	47,646	60,279	64,330
Natural gas sales ⁽⁶⁾	(Mcf/d)	27,326	29,651	34,895

1. Produced volumes that were not sold in the period and instead resulted in an increase in crude inventories held in storage.

2. Volumes purchased for trading and diluent purposes to fulfill pipeline take-or-pay agreements and pipeline quality specifications.

3. Volumes from E&E assets are excluded from total sales volumes because E&E revenues and costs are capitalized under IFRS.

4. Trading volumes sold that were purchased to meet volumes required for pipeline take-or-pay agreements.

5. Mainly corresponds to volumetric compensation and oil refined for 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.

During the first quarter of 2018, oil inventory increased significantly in comparison with the previous quarter and the first quarter of 2017 primarily due to one oil cargo that was planned for shipment during the first quarter of 2018 but was not shipped until April and therefore could not be recognized as sales in the first quarter. With this cargo delivered in April, sales volumes will be higher for the second quarter. Frontera expects sales volumes to normalize over the balance of 2018.

Operational Update

The Company continues to improve its reservoir management practices through various technical studies and detailed reservoir management work. These activities have improved the overall production decline, reduced overall operating costs, and positioned the Company to grow its reserves base. The following producing blocks continue to be positively affected by this work:

- Quifa block - During the first quarter of 2018, the Company drilled multiple horizontal wells in higher oil producing zones and defined a significant number of future development wells as a result of the reservoir studies completed in 2017. Changes to the drilling and completion practices have contributed to an overall improvement in well performance. The vertical wells drilled outside of the previous mapped field boundaries successfully encountered new areas of oil saturated reservoir. New reserves are expected to be booked and have defined up new development areas for drilling in 2018 and beyond.
- Guatiquia block - The continued drilling of development wells in the Ardilla, Ceibo and Avispa fields (“ACA”) within the block increased the potential area for the pool, thereby adding potential new reserve volumes and has assisted in identifying new future development well locations. Further exploration drilling to evaluate the near-field exploration success achieved at the end of 2017 resulted in an increase of the Alligator discovery located on the west of the main ACA fields. This expansion is expected to allow the Company to increase production from the Guatiquia block and book additional reserves at the end of 2018. The reservoirs within the ACA fields continued to perform with lower production decline than expected, which has resulted in the Company delaying the near-term drilling of injector wells for reservoir pressure maintenance.

- Orito and Neiva blocks - The reservoir modelling process on the Orito block is nearly complete and will allow the Company to evaluate the potential for implementing a water injection program. The Company continues to monitor the pilot water injection program implemented at the Neiva block to enhance recovery. As of the date hereof, there has been a significant increase in production as a result of this pilot program.
- Cubiro block - The Company implemented a pilot secondary recovery water flood program at the beginning of the first quarter of 2018. As a result of the positive response in the reservoir and increased production rates, the Company is planning to expand this water flood program during the remainder of 2018.

Netbacks

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

	Q1 2018		Q4 2017		Q1 2017	
	(\$/boe)	\$M	(\$/boe)	\$M	(\$/boe)	\$M
Combined price (including realized loss on risk management contracts)⁽¹⁾	52.36	247,141	53.26	320,868	45.95	291,367
Production cost	(12.47)	(74,322)	(13.13)	(77,860)	(9.43)	(61,527)
High-price participation payments and cash royalties	(1.30)	(7,751)	(1.23)	(7,305)	(0.90)	(5,873)
Transportation cost	(12.68)	(75,578)	(14.28)	(84,682)	(13.98)	(91,252)
Diluent cost	(1.49)	(8,865)	(1.01)	(6,016)	(1.05)	(6,869)
Total operating cost⁽²⁾	(27.94)	(166,516)	(29.65)	(175,863)	(25.36)	(165,521)
Operating Netback	24.42	80,625	23.61	145,005	20.59	125,846
Fees paid on suspended pipeline capacity ⁽²⁾	(6.02)	(35,904)	(4.16)	(24,656)	(4.15)	(27,100)
Share of income from associates – pipelines ⁽³⁾	2.95	17,607	2.38	14,130	2.05	13,380
Adjusted Netback	21.35	62,328	21.83	134,479	18.49	112,126
General and administrative ⁽⁴⁾	(3.70)	(22,053)	(4.12)	(24,450)	(4.24)	(27,706)
Cash finance costs ⁽⁵⁾	(1.05)	(6,250)	(1.05)	(6,250)	(0.96)	(6,250)
Other cash costs ⁽⁶⁾	0.04	235	(1.53)	(9,084)	0.09	590
Adjusted FFO Netback	16.64	34,260	15.13	94,695	13.38	78,760
Total production volume (boe/d)⁽⁷⁾	66,227		64,445		72,524	
Sales volume (D&P) (boe/d)⁽⁸⁾	52,440		65,481		70,452	

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

1. Per boe price calculated over sales volume D&P, in the "Realized and Reference Price" section on page 8.

2. "Operating Costs" section on page 9.

3. Share of income from associates – pipelines, in the "Non-Operating Costs" section on page 10.

4. General and administrative costs on page 10.

5. Finance costs in the "Non-Operating Costs" section on page 10.

6. Mainly includes dividends from associates, Frontera's share of income (loss) from associates, income tax, equity tax paid (equity tax was eliminated on December 31, 2017), realized foreign exchange, inventory fluctuation, overlift/settlement and settlement of asset retirement obligations.

7. Production and Development Review section on page 5.

8. Sales volumes D&P excludes E&E as the revenues and costs are capitalized under IFRS.

Operating Netback was \$24.42/boe for the first quarter of 2018, 19% higher than \$20.59/boe for the same period in 2017 and 3% higher than \$23.61/boe in the fourth quarter of 2017. The increase in Operating Netback from the prior year period is largely attributable to higher realized prices from the improvement in the Brent oil benchmark prices, which is partially offset by higher production costs as a result of the reactivation of Block 192. During the quarter, the Company lowered its transportation costs by reducing its utilization of the Bicentenario system which has a higher tariff than alternative pipelines.

Adjusted Netback was \$21.35/boe for the first quarter of 2018, 15% higher than \$18.49/boe for the same period in 2017 and marginally lower than \$21.83/boe in the previous quarter. The increase from the prior year period was the result of the higher Operating Netback partially offset by increased fees paid for commitments on pipeline capacity at the Bicentenario system which was not operational for 81 days compared with 50 days in the first quarter of 2017.

Adjusted FFO netback was \$16.64/boe for the first quarter of 2018, 24% higher than \$13.38/boe in the first quarter of 2017, primarily due to higher realized prices from the improvement in global oil prices.

Realized and Reference Price

		Q1 2018	Q4 2017	Q1 2017
Reference price				
Brent	(\$/bbl)	67.23	61.46	54.57
Average realized prices				
Realized oil price	(\$/bbl)	63.43	57.76	48.64
Realized natural gas price	(\$/Mcf)	4.08	3.78	3.74
Realized natural gas price ⁽¹⁾	(\$/boe)	23.25	21.55	21.29
Combined price before risk management contracts	(\$/boe)	59.75	54.88	46.26
Realized loss on risk management contracts	(\$/boe)	(8.98)	(2.93)	(1.39)
Other revenue ⁽²⁾	(\$/boe)	1.59	1.31	1.08
Combined realized price after risk management contracts	(\$/boe)	52.36	53.26	45.95

1. Refer to "Further Disclosures" section on page 20 for conversion factor.

2. Mainly includes income from infrastructure assets.

The average Brent oil benchmark price increased by \$12.66/bbl, or 23%, to an average of \$67.23/bbl in the first quarter of 2018 from \$54.57/bbl in the same period of 2017. Brent oil prices continue to improve based on strong global oil demand and lower oil inventories, higher than expected compliance rates from Organization of Petroleum Exporting Countries ("OPEC") and Non-OPEC, and higher geopolitical risk.

During the first quarter of 2018, the differential between the Company's oil sales and Brent oil prices narrowed by \$2.13/bbl compared with the first quarter of 2017. The tightening in the differentials was the result of new market strategies and the ability to meet demand in the U.S. West Coast market as the deficit of crude barrels in the region persisted.

Sales

(in thousands of US\$)	Three months ended March 31	
	2018	2017
Oil and natural gas sales and other revenue	289,534	300,153
Sales of oil and natural gas for trading	2,327	25,271
Total sales	291,861	325,424
Realized loss on risk management contracts	(42,393)	(8,786)
Total sales after realized loss on risk management contracts	249,468	316,638
Total sales after realized loss on risk management contracts excluding trading revenue	247,141	291,367
\$/per volume sold	52.36	45.95

Total sales after realized loss on risk management contracts during the quarter were \$249.5 million, 21% lower compared to the same period in 2017. In Colombia, total sales were \$248.4 million for the three months ended March 31, 2018 compared to \$285.9 million in the prior year period, as a result of lower production volumes. In Peru, total sales were \$41.1 million for the three months ended March 31, 2018 compared to \$14.3 million in the prior year period. The increase in total sales was primarily due to higher volumes sold from the reactivation of Block 192. The following table illustrates the various factors that have impacted sales volume movements from the first quarter of 2017 to this quarter:

Total sales after realized loss on risk management contracts movement reconciliation

(in thousands of US\$)	
Total sales after realized loss on risk management contracts for the three months ended March 31, 2017	\$ 316,638
Decrease due to 26% (18,012 boe/d) reduction in produced and sold volumes	(76,090)
Decrease due to 5,410 bbl/d lower volume of trading	(23,556)
Realized loss on risk management contracts	(33,607)
Increase due to 29% higher realized prices before risk management contracts	64,269
Other revenue increase	1,814
Total sales after realized loss on risk management contracts for the three months ended March 31, 2018	\$ 249,468

(in thousands of US\$)

Total sales after realized loss on risk management contracts for the three months ended December 31, 2017	\$	335,346
Decrease due to 22% (13,041 boe/d) reduction in produced and sold volumes		(71,599)
Decrease due to 2,707 bbl/d lower volume of trading		(12,681)
Realized loss on risk management contracts		(24,752)
Increase due to 9% higher realized prices before risk management contracts		23,511
Other revenue decrease		(357)
Total sales after realized loss on risk management contracts for the three months ended March 31, 2018	\$	249,468

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

Operating Costs

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Production cost	\$ 74,322	\$ 61,527
High-price participation payments and cash royalties	7,751	5,873
Transportation cost	75,578	91,252
Diluent cost	8,865	6,869
Total operating cost	\$ 166,516	\$ 165,521
Average operating cost \$/per boe production	27.94	25.36
Fees paid on suspended pipeline capacity	35,904	27,100
Purchase of oil and natural gas for trading	1,743	24,972
Inventory valuation	(9,813)	(411)
Overlift (settlement)	(17,019)	6,408
Total cost	\$ 177,331	\$ 223,590

During the first quarter of 2018, total operating costs were \$166.5 million, slightly higher than \$165.5 million in the same period of 2017. During the quarter, the Company reported lower transportation costs from a reduction in average pipeline tariff rates; however, it was partially offset by higher production costs relating to the reactivation of operations at Block 192. Total cost for the quarter was \$177.3 million, a decrease of \$46.3 million or 21% compared to the prior year period. The decrease in the quarter was mainly due to an inventory increase due to the timing of cargo shipments, lower costs from trading activities, and the settlement of an overlift position from the fourth quarter of 2017.

Depletion, Depreciation and Amortization

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Depletion, depreciation, and amortization	\$ 72,673	\$ 101,794
\$/per boe production	12.19	15.60

Depletion, depreciation and amortization (“DD&A”) decreased by \$29.1 million, or 29%, mainly due to lower sales volumes, higher oil inventories, and a lower depletable base as a result of impairment charges recognized during 2017.

Impairment and Impairment Reversal

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Impairment (reversal) of oil and natural gas properties and plant and equipment	\$ —	\$ (11,625)
Impairment of asset held for sale - PEL	9,125	—
Impairment of investments and other receivables	11,216	1,178
Total impairment (reversal)	\$ 20,341	\$ (10,447)

During the three months ended March 31, 2018, an impairment charge of \$9.1 million was recognized with respect to the sale of the Company's transmission line assets owned by PEL (the sale was closed in the second quarter of 2018) and an impairment of \$11.2 million related to the Company's investment in Interamerican Energy Corporation.

During the three months ended March 31, 2017, in updating the assessment of the fair value of assets being reclassified to held for sale, the Company reversed the following impairment charges previously recognized: exploration and evaluation assets in the Peru Cash Generating Unit ("CGU") by \$10.4 million and oil and natural gas properties in the Colombia Central CGU by \$1.3 million. The Company also recognized \$1.2 million related to certain accounts receivable balances with doubtful recovery, which were fully written off.

General and Administrative

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
General and administrative	\$ 22,053	\$ 27,706
\$/per boe production	3.70	4.24

General and administrative expenses decreased by \$5.7 million, or 20%, for the first quarter of 2018 compared to the prior year period, primarily due to a reduction in employee-related costs and the Company's continued efforts to reduce overhead cost.

Restructuring, severance and other costs

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Restructuring and other costs	469	—
Severance	2,369	5,946
Total restructuring, severance and other costs	2,838	5,946

Restructuring, severance and other costs decreased by \$3.1 million, or 52%, primarily a result of higher expenses recorded in the first quarter of 2017 following the completion of the Company's restructuring transaction in November 2016. In 2018, the Company will continue to invest in initiatives that are expected to deliver continued process improvements, particularly in areas relating to controls, compliance and operational efficiencies.

Non-Operating Costs

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Cash finance costs	(6,250)	(6,250)
Non-cash finance income	2,003	1,353
Total finance costs, net	(4,247)	(4,897)
Cash finance costs \$/per boe production	(1.05)	(0.96)
Share of income from associates - pipelines	17,607	13,380
Share of income from associates - and other	18,152	10,608
Total share of income from associates	35,759	23,988
Share of income from associates - pipelines \$/per boe production	2.95	2.05
Foreign exchange gain	19,005	11,246
Realized loss on risk management contracts	(42,393)	(8,786)
Unrealized gain on risk management contracts	17,313	40,145
Total (loss) gain on risk management contracts	(25,080)	31,359
Current income tax expense	(10,329)	(10,034)
Deferred income tax expense	(417)	—
Total income tax expense	(10,746)	(10,034)
Income tax expense \$/per boe production	(1.80)	(1.54)

Finance Costs, Net

Finance costs include interest expense on the Company's long-term debt, short-term borrowings, finance leases, and fees on letters of credit, net of interest income received on cash deposits. During the first quarter of 2018, finance costs remained relatively consistent with the prior year period primarily due to the fixed interest rate on the Company's long-term debt.

Share of Income from Associates

The Company's share of income from associates increased by \$11.8 million, or 49%, in the first quarter of 2018 compared to the same period in 2017 primarily due to the functional currency of certain associates being the Colombian peso ("COP"), which appreciated 6.8% relative to the U.S. dollar.

Foreign Exchange

The Company is exposed to foreign currency fluctuations from the movement of the COP against the U.S. dollar as a significant portion of working capital and operating expenditures are denominated in COP. The foreign exchange gain in the first quarter of 2018 increased by \$7.8 million, or 69%, compared with the prior year period primarily due to the strengthening of the COP relative to the U.S. dollar and the related impact from the translation of the Company's net working capital.

(Loss) Gain on Risk Management Contracts

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of oil production. As at March 31, 2018, the Company hedged approximately 60% of its estimated production up to and including October 2018. The objective for 2018 is to hedge the maximum allowable under the Note Indenture (as defined herein) and Secured LC Agreement (as defined herein) 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 March 31, 2018, the Company had outstanding hedge positions for approximately 8.4 MMbbl with average floor and ceiling strike Brent prices of \$51.98/bbl and \$58.24/bbl, respectively, with a net current liability of \$86.4 million.

Type of Instrument	Settlement Month	Benchmark	Notional Amount / Volume (bbl)	Put/ Call Strike	Carrying Amount (in thousands of US\$)		
					Assets	Liabilities	
Collar	April 2018	Brent	1,200,000	50.77 / 55.73	—	16,267	
Collar	May 2018	Brent	1,200,000	51.10 / 55.86	—	15,588	
Collar	June 2018	Brent	1,200,000	51.23 / 55.91	—	15,012	
Collar	July 2018	Brent	1,200,000	52.00 / 59.31	—	10,984	
Collar	August 2018	Brent	1,200,000	52.42 / 60.05	—	10,010	
Collar	September 2018	Brent	1,200,000	53.42 / 61.63	—	8,342	
Collar/ Call Spreads	October 2018	Brent	1,200,000	52.92 / 59.22	—	10,231	
Total as at March 31, 2018					\$	— \$	86,434

The Company's risk management contracts may expose it to the risk of financial loss in certain circumstances, including instances in which production falls short of the hedged volumes, the price of oil increases above the call strike price, or if the counterparties fail to perform under those arrangements.

Income Tax Expense

The current income tax expense includes a minimum income tax ("presumptive tax") of \$7.6 million, \$2.4 million from dividends received on investments in associates, and \$0.3 million of current taxes in countries other than Colombia.

For more information, please refer to Note 8 - Income Tax - from the Interim Financial Statements.

Capital Expenditures

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Maintenance and development drilling	\$ 43,783	\$ 35,117
Facilities and infrastructure	24,836	1,421
Exploration activities ⁽¹⁾	7,655	971
Administrative assets and other projects	2,567	1,290
Total capital expenditures	\$ 78,841	\$ 38,799

1. Includes E&E assets revenues and costs.

Capital expenditures were \$78.8 million in the first quarter of 2018 compared to \$38.8 million in the first quarter of 2017. The increase in capital expenditures was due to higher development drilling and exploration activities, as well as higher costs associated with the expansion of production infrastructure in the Guatiquia, Corcel and Cravoviejo blocks.

Selected Quarterly Information

		2018		2017			2016		
		Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial and operational results:									
Net production after royalties ^(1,2)	(boe/d)	66,227	64,445	71,068	72,370	72,524	69,432	75,096	127,951
Oil production	(boe/d)	61,352	59,131	65,641	66,448	66,035	62,229	67,128	118,526
Natural gas production	(Mcf/d)	27,788	30,290	30,934	33,755	36,987	41,057	45,418	53,723
Oil and natural gas sales	(boe/d)	52,440	65,481	63,162	64,908	70,452	67,470	81,877	109,736
Combined price (including realized (loss) gain on risk management contracts)	(\$/boe)	52.36	53.26	47.86	46.28	45.95	41.92	40.83	37.60
Realized oil and natural gas and other revenue price	(\$/boe)	61.34	56.19	47.55	45.71	47.34	43.44	40.83	37.60
Realized (loss) gain on risk management contracts	(\$/boe)	(8.98)	(2.93)	0.31	0.57	(1.39)	(1.52)	—	—
Brent	(\$/bbl)	67.23	61.46	52.17	50.79	54.57	51.06	46.99	47.03
Operating cost	(\$/boe)	(27.94)	(29.65)	(24.32)	(25.97)	(25.36)	(27.40)	(24.06)	(20.30)
Operating Netback ⁽³⁾	(\$/boe)	24.42	23.61	23.54	20.31	20.59	14.52	16.77	17.30
Adjusted Netback ⁽³⁾	(\$/boe)	21.35	21.83	20.68	19.13	18.49	13.89	12.91	17.25
Adjusted FFO Netback ⁽³⁾	(\$/boe)	16.64	15.13	12.64	11.76	13.38	2.48	2.55	9.17
Total sales after realized (loss) gain on risk management contracts	(\$M)	249,468	335,346	307,080	299,452	316,638	269,772	308,705	376,403
Net (loss) income ⁽⁴⁾	(\$M)	(3,121)	(32,544)	(141,115)	(51,542)	8,498	4,025,194	(557,068)	(118,654)
Per share – basic ⁽⁵⁾	\$	(0.06)	(0.65)	(2.82)	(1.03)	0.17	80.50	(176,835.08)	(37,665.40)
Per share – diluted ⁽⁵⁾	\$	(0.06)	(0.65)	(2.82)	(1.03)	0.17	80.47	(176,835.08)	(37,665.40)
Operating EBITDA ⁽³⁾	(\$M)	85,988	105,010	105,885	86,857	92,442	44,275	89,846	120,452
Adjusted EBITDA ⁽³⁾	(\$M)	86,654	1,999	44,203	87,389	115,058	(1,967)	37,689	126,083
Adjusted FFO ⁽³⁾	(\$M)	34,260	94,695	47,889	46,151	78,760	8,256	43,036	44,314
Capital expenditures ⁽⁶⁾	(\$M)	78,841	111,213	48,563	37,826	38,799	64,707	33,631	50,044
Total assets	(\$M)	2,664,920	2,579,651	2,546,631	2,621,871	2,772,423	2,741,719	2,403,602	2,990,699

1. Net production after royalties represents the Company's working interest volumes, net of royalties and internal consumption.

2. BOE has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.

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

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

5. Both basic and diluted weighted average numbers of Common Shares for the three months ended March 31, 2018, were 50,005,832 (March 31, 2017: 50,002,363 and 50,025,751, respectively).

6. Capital expenditures includes revenues from E&E assets for the three months ended March 31, 2018 and 2017, of \$6.5 million and \$4.8 million, respectively.

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

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

Non-IFRS Measures

This report contains the following financial terms that 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:

(in thousands of US\$)	Three Months Ended March 31	
	2018	2017
Net (loss) income ⁽¹⁾	\$ (3,121)	\$ 8,498
Adjustments		
Income tax expense	10,746	10,034
Depletion, depreciation and amortization	72,673	101,794
Impairment (reversal)	20,341	(10,447)
Finance costs, net	4,247	4,897
Restructuring, severance and other costs	2,838	5,946
Equity tax	—	11,694
Other loss (income)	604	(2,498)
Foreign exchange unrealized gain	(21,674)	(14,860)
Adjusted EBITDA	86,654	115,058
Unrealized gain on risk management contracts	(17,313)	(40,145)
Share of income from associates	(35,759)	(23,988)
Gain attributable to non-controlling interest	12,779	10,783
Share-based compensation	1,054	20
Foreign exchange realized loss	2,669	3,614
Fees paid on suspended pipeline capacity	35,904	27,100
Operating EBITDA	85,988	92,442

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 natural gas industry to analyze financial and operating performance expressed as profit per barrel.

- Operating Netback represents realized price per barrel including realized gain or loss from risk management contracts, less production costs, high-price participation payments and cash royalties, transportation and diluent 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 pipeline investments that are in addition to oil and natural gas production and the take-or-pay fees paid on suspend pipeline capacity.
- Adjusted Funds Flow from Operations Netback ("**Adjusted FFO Netback**") represents Adjusted Netback less corporate cash expenses (G&A and cash finance costs) and other cash items (primarily dividends and Frontera's share of income from associates, income tax, equity tax paid, realized foreign exchange, inventory fluctuations, overlift (settlement) and settlement of asset retirement obligations).

Refer to the "Netbacks" section on page 7.

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 also excludes settlement of asset retirement obligations, one-time expenses for the Company not related to ongoing operations such as restructuring, severance and other costs, and loss (gain) from past assets.

Refer to the "Performance Highlights - Financial" section on page 4 for FFO to Adjusted FFO reconciliation.

5. PRINCIPAL PROPERTIES

	Working Interest	Operated	Gross Acres	Net Acres
<u>Colombia Central</u>				
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⁾	49.99%	Non-operated	141,308	70,654
Muisca ⁽²⁾	49.99%	Non-operated	585,126	292,563
<u>Colombia North</u>				
La Creciente	100.00%	Operated	26,653	26,653
Guama	100.00%	Operated	70,995	70,995
CR-1	60.00%	Operated	307,384	184,431
<u>Colombia South</u>				
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 ⁽³⁾	40.00%	Non-operated	258,676	103,470
Tinigua	50.00%	Non-operated	105,467	52,734
<u>Peru</u>				
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. The Company's participating interest in these blocks is through the 49.99% of the outstanding shares held by PRE-PSIE Coöperatief U.A. in Maurel & Prom Colombia B.V.

3. The Company has requested the transfer of investment and overall relinquishment of its interest in the block. The application is pending ANH approval.

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 participating interest in Lot 116 to the Company. The transfer of all participating interest in Lot 116 to the Company was approved by PeruPetro S.A. and is pending the execution of final documentation to conclude the formalization of the transfer.

5. Block 192 is operated by us through a service contract with PeruPetro S.A., the Peruvian state-owned hydrocarbons company.

6. LIQUIDITY AND CAPITAL RESOURCES

As at March 31, 2018, the Company had total cash of \$695.9 million, an increase of \$135.5 million compared to the prior year-end. This increase was primarily due to \$30.3 million cash generated from operating activities and the receipt of gross cash proceeds from the sale of PEL (\$20.0 million) and the Papua New Guinea assets sale (\$57.0 million). These factors were partially offset by net capital expenditures of \$78.8 million in the quarter. In accordance with the Company's investment policy, available cash balances are held in high interest savings accounts, term deposits, and Colombian mutual funds with high credit ratings and short-term liquidity.

As at March 31, 2018, the Company had total working capital of \$343.2 million, an increase of \$33.2 million compared to \$310.0 million at the prior year-end. The increase in working capital was mainly the result of the Company generating operating cash flow in excess of capital expenditures for the three months ended March 31, 2018, and increase in inventory balances.

The Company's long-term borrowing consists of \$250.0 million of senior secured notes due in 2021, which carry a fixed interest rate of 10% per annum ("**Senior Secured Notes**"). 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 the same pool of security on a first and second lien basis.

Covenant/Limitation on Indebtedness

Under the indenture for the Senior Secured Notes (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 is the Consolidated Adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period.

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 March 31, 2018, the Company is in compliance with such covenants.

Letters of Credit and Guarantees

The Company has a letter of credit facility with a syndicate of lenders that matures on June 22, 2018 ("**Secured LC Agreement**"). As at March 31, 2018, the outstanding letters of credit under the Secured LC Agreement totalled \$ 81.9 million, compared to \$82.3 million as at December 31, 2017. The lenders receive an amount equal to 5.0% per annum, computed on a quarterly basis in advance and due and payable on the first business day of each fiscal quarter, calculated on the undrawn portion, if any, of outstanding letters of credit, as a fee for their risk of drawing. The Secured LC Agreement contains covenants and events of default substantially similar to those in the Indenture. As of the date hereof, the Company is in compliance with such covenants.

The Company has various guarantees in place in the normal course of business. As at March 31, 2018, we had issued letters of credit and guarantees for \$100.5 million, including: (i) \$88.5 million of letters of credit, (ii) \$5.0 million of cash collateralized letters of credit, and (iii) term deposits in Colombian currency for \$7.0 million for exploration and operational commitments.

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.

Commitments and Contingencies

The following table summarizes the Company's estimated commitments, on an undiscounted basis, at March 31, 2018:

(in thousands of US\$)	2018	2019	2020	2021	2022	2023 and Beyond	Total
Financial							
Debt	—	—	—	250,000	—	—	250,000
Finance lease	5,107	6,778	6,797	4,513	—	—	24,867
Transportation Commitments							
ODL Ship-or-Pay Agreement	37,175	49,052	30,073	1,144	—	165	117,609
Bicentenario Ship-or-Pay Agreement	104,265	139,020	139,020	139,020	139,020	211,623	871,968
Transportation and processing commitments	206,023	234,509	233,763	232,939	192,022	723,325	1,822,581
Exploration Commitments							
Minimum work commitments	113,996	31,413	54,615	27,546	—	—	227,570
Other Commitments							
Operating purchases and leases	46,859	13,881	13,752	12,633	11,512	7,738	106,375
Community obligations	7,002	821	821	554	554	1,108	10,860
Total	520,427	475,474	478,841	668,349	343,108	943,959	3,431,830

Puerto Bahia - Equity Contribution Agreement

On October 4, 2013, Pacinfra Holding Ltd. (a subsidiary of the Company), Pacific Infrastructure Ventures, Inc., Puerto Bahia (owned by PII, Notes 13 of the Interim Financial Statement) 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) to Puerto Bahia up to the aggregate amount of \$130.0 million, when it is determined that there are certain deficiencies related to operation and maintenance of the port facility and Puerto Bahia's ability to make payments towards its bank debt obligations. On 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. Accordingly, the deficiency amount, due May 31, 2018, was included under "transportation and processing commitments" in the commitments table.

Contingencies

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

No material changes have occurred with respect to the matters disclosed in "Note 24 - Commitments and Contingencies" of the Company's 2017 Audited Financial Statements.

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at May 9, 2018:

	Number
Common Shares	50,005,832
Deferred Share Units ("DSUs") ⁽¹⁾	56,080
Restricted Share Units ("RSUs") ⁽²⁾	739,253

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 objective). The value of RSUs increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of an RSU holder with Shareholders. Settlement may be made, in the sole discretion of the Compensation and Human Resources Committee, in Common Shares, cash or a combination thereof. Vesting of RSUs is determined by the Compensation and Human Resources Committee in its sole discretion and specified in the Award agreement pursuant to which the RSU is granted.

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

8. RELATED-PARTY TRANSACTIONS

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

(in thousands of US\$)		Accounts Receivable ⁽¹⁾	Accounts Payable	Commitments	Cash Advance	Loans Receivable ⁽²⁾	Interest Receivable ⁽²⁾	Convertible Debentures ⁽²⁾
ODL ⁽¹⁾	2018	21,085	209	117,609	—	—	—	—
	2017	421	231	130,303	—	—	—	—
Bicentenario ⁽¹⁾	2018	44,257	251	871,968	87,278	—	—	—
	2017	12,660	469	902,375	87,278	—	—	—
PII - Sociedad Portuaria Puerto Bahia S.A	2018	7,453	1,687	180,685	17,741	76,552	28,384	—
	2017	5,926	1,598	158,179	17,741	76,552	26,331	—
Interamerican - Consorcio Genser Power - Proelectrica - Termomorichal	2018	158	3	—	—	2,224	446	—
	2017	145	72	—	—	2,224	362	—
CGX	2018	128	—	—	—	15,467	1,848	1,500
	2017	120	—	—	—	14,622	1,516	1,500

For the three months ended March 31, (in thousands of US\$)		Sales	Purchases / Services	Interest Income ⁽²⁾
ODL	2018	1,009	11,962	—
	2017	997	12,265	—
Bicentenario	2018	—	28,098	—
	2017	—	36,006	—
PII - Sociedad Portuaria Puerto Bahia S.A	2018	—	6,333	2,053
	2017	—	7,296	1,987
Interamerican - Consorcio Genser Power - Proelectrica - Termomorichal	2018	3	2	84
	2017	333	16	83
CGX	2018	151	—	332
	2017	—	—	158

1. Accounts receivable balances for ODL and Bicentenario include \$48.4 million of dividends receivable (December 31, 2017: \$Nil).

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

Except as described below, there have been no significant changes to any transaction with a related-party since December 31, 2017. For more information, refer to the Company's management discussion and analysis for the year ended December 31, 2017.

- CGX - The Company has a series of loans with CGX. The Company also has service arrangements with respect to certain corporate administrative services and technical service support provided for CGX's operations in Guyana. On April 26, 2018, the Company and CGX entered into an amended and restated bridge loan facility, pursuant to which the previous bridge loan facility dated April 26, 2017 was amended to: (i) increase the principal amount available under the facility to \$14.1 million, and (ii) extend the maturity date of the facility from April 25, 2018 to July 31, 2018.

9. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of risks, including but not limited to, operational, financial, competitive, political and environmental risks.

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

10. 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 2 of the Interim Financial Statements. The Company has not early adopted any standard, interpretation, or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 2 of the Interim Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the 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 2 of the Interim Financial Statements.

11. INTERNAL CONTROL

In accordance with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Interim Filings." This Certification requires certifying officers to certify, among other things, that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Controls over Financial Reporting ("**ICFR**") as those terms are defined in NI 52-109.

The 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.

There have been no changes in the Company's ICFR during the quarter ended March 31, 2018 that have materially affected, or are reasonably likely to materially affect, its ICFR.

The Company's DC&P is designed to provide reasonable assurance that:

- Material information relating to the Company is made known to the Company's certifying officers by others, particularly during the period in which the interim filings are being prepared.
- Information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized, and reported within the time period specified in securities legislation.

12. 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.

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
Mbbl	Thousand barrels	\$MM	Million U.S. dollars