CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
YEAR ENDED DECEMBER 31, 2017

FINANCIAL & OPERATING HIGHLIGHTS

(in United States dollars (tabular amounts in thousands) except as otherwise noted)

Financial	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Total petroleum and natural gas revenues, net of royalties	**42,092**	41,967	—	**158,908**	147,985	7%
Adjusted petroleum and natural gas revenues, net of royalties[2]	**46,285**	47,943	(3%)	**179,525**	173,184	4%
Cash flow provided by operating activities	**25,001**	30,289	(17%)	**65,346**	73,577	(11%)
Per share – basic ($)[1]	**0.14**	0.17	(18%)	**0.37**	0.44	(16%)
Per share – diluted ($)[1]	**0.14**	0.17	(18%)	**0.37**	0.44	(16%)
Adjusted funds from operations [1][2]	**20,857**	41,979	(50%)	**84,804**	113,019	(25%)
Per share – basic ($)[1]	**0.12**	0.24	(50%)	**0.48**	0.68	(29%)
Per share – diluted ($)[1]	**0.12**	0.24	(50%)	**0.48**	0.67	(28%)
Net income (loss) and comprehensive income (loss)	**(150,343)**	20,331	n/a	**(148,029)**	23,638	n/a
Per share – basic ($)	**(0.85)**	0.12	n/a	**(0.85)**	0.14	n/a
Per share – diluted ($)	**(0.85)**	0.12	n/a	**(0.85)**	0.14	n/a
Capital expenditures, net, including acquisitions	**41,652**	58,638	(29%)	**121,202**	107,930	12%
Adjusted capital expenditures, net, including acquisitions[1]	**44,373**	59,691	(26%)	**125,407**	110,224	14%
				Dec 31, 2017	Dec 31, 2016	Change
Cash				**39,071**	66,283	(41%)
Restricted cash				**27,919**	62,073	(55%)
Working capital surplus				**110,401**	64,899	70%
Bank debt				**294,590**	250,638	18%
Total assets				**696,443**	787,508	(12%)
Common shares, end of period (000's)				**176,109**	174,359	—

Operating	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Petroleum and natural gas production, before royalties (boepd)						
Petroleum [3]	**3,008**	3,616	(17%)	**3,315**	4,012	(17%)
Natural gas	**14,569**	14,112	3%	**13,765**	11,930	15%
Total [2]	**17,577**	17,728	(1%)	**17,080**	15,942	7%
Petroleum and natural gas sales, before royalties (boepd)						
Petroleum [3]	**3,003**	3,657	(18%)	**3,321**	4,019	(17%)
Natural gas	**14,379**	13,986	3%	**13,648**	11,830	15%
Total [2]	**17,382**	17,643	(1%)	**16,969**	15,849	7%
Realized contractual sales, before royalties (boepd)						
Natural gas	**14,950**	14,653	2%	**14,125**	12,357	14%
Colombia oil	**1,820**	2,026	(10%)	**1,915**	2,315	(17%)
Ecuador tariff oil [2]	**1,183**	1,631	(27%)	**1,406**	1,704	(17%)
Total [2]	**17,953**	18,310	(2%)	**17,446**	16,376	7%
Operating netbacks ($/boe) [1]						
Total natural gas	**20.24**	24.50	(17%)	**22.21**	25.83	(14%)
LLA-23 (oil)	**20.14**	14.80	36%	**20.00**	12.05	66%
Ecuador (tariff oil) [2]	**38.54**	38.54	—	**38.54**	38.54	—
Total [2]	**21.84**	24.00	(9%)	**23.15**	24.93	(7%)

(1) Non-IFRS measures – see "Non-IFRS Measures" section within MD&A.
(2) Inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section within MD&A.
(3) Includes tariff oil production and sales related to the Ecuador IPC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. and its subsidiaries ("Canacol" or the "Corporation") are primarily engaged in petroleum and natural gas exploration and development activities in Colombia. The Corporation's head office is located at 2650, 585 - 8th Avenue SW, Calgary, Alberta, T2P 1G1, Canada. The Corporation's shares are traded on the Toronto Stock Exchange (the "TSX") under the symbol CNE, the OTCQX in the United States of America under the symbol CNNEF, the Bolsa de Valores de Colombia under the symbol CNEC and the Bolsa Mexicana de Valores under the symbol CNEN.

Advisories

The following management's discussion and analysis ("MD&A") is dated March 23, 2018 and is the Corporation's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Corporation's financial position. Comments relate to and should be read in conjunction with the audited consolidated financial statements of the Corporation for the year ended December 31, 2017 and 2016 (the "financial statements"). The financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), and all amounts herein are expressed in United States dollars, unless otherwise noted, and all tabular amounts are expressed in thousands of United States dollars, except per share amounts or as otherwise noted. Additional information for the Corporation, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

Forward-Looking Statements *– Certain information set forth in this document contains forward-looking statements. All statements other than historical fact contained herein are forward-looking statements, including, without limitation, statements regarding the future financial position, business strategy, production rates, and plans and objectives of or involving the Corporation. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control, including the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal and external sources. In particular with respect to forward-looking comments in this MD&A, readers are cautioned that there can be no assurance that the Corporation will complete its planned capital projects on schedule or that petroleum and natural gas production will result from such capital projects, that additional natural gas sales contracts will be secured, that the Ecuadorian government will not renegotiate tariff prices on certain fixed priced contracts during low oil price environment, or that hydrocarbon-based royalties assessed will remain consistent, or that royalties will continue to be applied on a sliding-scale basis as production increases on any one block, or that the planned divestiture of the Corporation's Colombian oil assets will be successful. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits the Corporation will derive therefrom.*

In addition to historical information, this MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook"). These statements are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; fluctuations in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; and risks associated with oil and gas operations, many of which are beyond the control of the Corporation. Accordingly, there is no representation by the Corporation that actual results achieved during the forecast period will be the same in whole or in part as those forecasted. Except to the extent required by law, the Corporation assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are qualified in their entirety by these cautionary statements.

Readers are further cautioned not to place undue reliance on any forward-looking information or statements.

***Non-IFRS Measures** – Due to the nature of the equity method of accounting the Corporation applies under IFRS 11 to its interest in the incremental production contract for the Libertador and Atacapi fields in Ecuador ("Ecuador IPC"), the Corporation does not record its proportionate share of revenues and expenditures as would be typical in oil and gas joint interest arrangements. Therefore, within this MD&A, management has provided supplemental measures of adjusted revenues and expenditures, which are inclusive of the Ecuador IPC, to supplement the IFRS disclosures of the Corporation's operations. Such supplemental measures should not be considered as an alternative to, or more meaningful than, the measures as determined in accordance with IFRS as an indicator of the Corporation's performance, and such measures may not be comparable to that reported by other companies.*

One of the benchmarks the Corporation uses to evaluate its performance is adjusted funds from operations. Adjusted funds from operations is a measure not defined in IFRS. It represents cash provided by operating activities before changes in non-cash working capital and decommissioning obligation expenditures, and includes the Corporation's proportionate interest of those items that would otherwise have contributed to funds from operations from the Ecuador IPC had it been accounted for under the proportionate consolidation method of accounting. The Corporation considers adjusted funds from operations a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Adjusted funds from operations should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. The Corporation's determination of adjusted funds from operations may not be comparable to that reported by other companies. The Corporation also presents cash flow from operations and adjusted funds from operations per share, whereby per share amounts are calculated using weighted-average shares outstanding consistent with the calculation of net income (loss) and comprehensive income (loss) per share.

The following table includes the Corporation's basic and dilutive weighted-average shares outstanding:

	Three months ended December 31,		**Year ended December 31,**	
	2017	2016	**2017**	2016
Weighted-average common shares	**175,988**	173,779	**175,180**	165,640
Effect of stock options	**1,893**	2,974	**1,820**	2,062
Weighted-average common shares outstanding, diluted	**177,881**	176,753	**177,000**	167,702

The following table reconciles the Corporation's cash provided by operating activities to adjusted funds from operations:

	Three months ended December 31,		**Year ended December 31,**	
	2017	2016	**2017**	2016
Cash flow provided by operating activities	**$ 25,001**	$ 30,289	**$ 65,346**	$ 73,577
Changes in non-cash working capital	**(8,428)**	4,865	**(450)**	14,243
Ecuador IPC revenue, net of current income taxes	**4,284**	6,825	**19,908**	25,199
Adjusted funds from operations	**$ 20,857**	$ 41,979	**$ 84,804**	$ 113,019

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, and is used to evaluate the Corporation's financial leverage. Operating netback is a benchmark common in the oil and gas industry and is calculated as total petroleum and natural gas sales, less royalties, less production and transportation expenses, calculated on a per barrel of oil equivalent ("boe") basis of sales volumes using a conversion. Operating netback is an important measure in evaluating operational performance as it demonstrates field level profitability relative to current commodity prices.

Working capital and operating netback as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

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 of natural gas to barrels of oil equivalent 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, we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Ministry of Mines and Energy of Colombia.

Results of Operations

For the three months ended December 31, 2017, the Corporation's production primarily consisted of natural gas from the Nelson, Palmer, Trombon and Nispero fields in the Esperanza block, the Clarinete field in the VIM-5 block and the Toronja field in the VIM-21 block, located in the Lower Magdalena Basin in Colombia. The Corporation's production also includes crude oil from the Leono, Labrador and Tigro fields in the LLA-23 block in the Llanos Basin in Colombia, tariff oil from the Ecuador IPC, and, to a lesser extent, crude oil from the Rancho Hermoso, VMM-2 and Santa Isabel properties in Colombia.

During the three months ended December 31, 2017, the Corporation drilled and tested the Pandereta-1 exploration well on its VIM-5 block, with gas encountered in the primary Ciénaga de Oro ("CDO") sandstone reservoir target as anticipated. The CDO reservoir was perforated between 7,742–7,778 and 7,810–7,830 feet measured depth ("ft md") and flowed at a final stable rate of 29 MMscfpd. The Corporation spud the Pandereta-2 exploration well on December 2, 2017 and targeted gas bearing reservoirs of the CDO reservoir approximately one kilometer ("km") to the west of the Pandereta-1 bottom hole location. Two separate production tests were performed in the CDO reservoir. The upper part of the CDO reservoir was perforated between 8,505 to 8,612 ft md and flowed at a final stable rate of 35 MMscfpd. Based upon this result, management has calculated an absolute open flow rate of 140 MMscfpd for the upper CDO for the Pandereta-2 exploration well. The testing results relating to the lower part of the CDO reservoir were inconclusive due to mechanical issues. The Pandereta-3 exploration well was spud in January 2018, and reached a total depth of 9,534 ft md in 13 days. It is located approximately one km to the northeast of the bottom hole location of the Pandereta-1 exploration well. The upper part of the CDO reservoir was perforated between 8,370 to 8,447 ft md and flowed at a final stable rate of 43 MMscfpd. Based upon this result, an absolute open flow rate of 168 MMscfpd was calculated for the upper part of the CDO reservoir. The lower and middle part of the CDO reservoir were perforated between 8,942 – 8,965 and 8,860 – 8,905 ft md and flowed at a final stable rate of 15 MMscfpd and 21 MMscfpd, respectively. The Corporation is currently planning to tie the Pandereta discovery into its operated gas processing facility located at Jobo by mid-year 2018.

During the three months ended December 31, 2017, the Corporation drilled the Canandonga-1 exploration well located six kms northeast of the Nelson gas field on its Esperanza block. The well reached a total depth of 9,300 ft md within the primary CDO sandstone reservoir, however due to drilling related problems, the well penetrated only the upper 713 feet of the CDO sandstone reservoir section before drilling operations were suspended, having penetrated approximately one third of the anticipated section of CDO sandstone reservoir. The Corporation plans to mobilize a workover rig to complete and test the Canandonga-1 discovery well in mid-year 2018.

In August 2017, the Corporation entered into an agreement with a group of private investors for the construction, operation and ownership of the 82 km Sabanas gas flowline (the "Sabanas Flowline") from its Jobo gas plant to the connection point with the Promigas S.A. gas pipeline at Bremen, Colombia. The Sabanas Flowline was completed in December 2017 and upon completion of the second gas compression station in February, 2018, the Sabanas Flowline reached its full transportation capacity of 40 MMscfpd. The Corporation has a 25.6% working interest in the Sabanas Flowline.

The Corporation, through a consortium, participated in an incremental production contract for the Libertador and Atacapi fields in Ecuador whereby the Corporation was entitled to a tariff price of $38.54/bbl for each incremental barrel of oil produced over a pre-determined production base curve. Such incremental production volumes are reported as production in this MD&A. As further described above, as required under IFRS 11, the Ecuador IPC is being accounted for under the equity method of accounting versus the proportionate consolidation method of accounting. For purposes of this MD&A, management has provided supplemental measures for adjusted revenues and expenditures, which are inclusive of the Ecuador IPC, to supplement the IFRS disclosures of the Corporation's operations. Subsequent to December 31, 2017, the Corporation sold its interest in the Ecuador joint venture investment for proceeds of $36.4 million.

For the three months ended December 31, 2017, the Corporation also had crude oil production from its LLA-23, Rancho Hermoso, VMM-2 and Santa Isabel properties in Colombia. The Corporation's Rancho Hermoso, VMM-2 and Santa Isabel properties individually contributed only a minor amount to total production in the three months ended December 31, 2017 and, therefore, were aggregated into a single group ("Other") for analysis purposes in this MD&A. These properties are susceptible to negative cash flows in a low oil price environment and the Corporation plans to shut-in any wells under its control that are uneconomic. As of the date of this MD&A, all wells at the Moloacan field in Mexico have been shut-in and the Corporation is currently in the process of relinquishing the field. The Corporation has classified certain petroleum blocks as held for sale as at December 31, 2017, due to its intention to sell the assets, which is expected to be completed in 2018.

In addition to its producing fields, the Corporation has interests in a number of exploration blocks in Colombia.

Average Daily Petroleum and Natural Gas Production and Sales Volumes

Production and sales volumes in this MD&A are reported before royalties.

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Production (boepd)						
Esperanza (gas)	**11,076**	8,168	36%	**10,299**	7,401	39%
VIM-5 (gas)	**3,277**	5,944	(45%)	**3,412**	4,529	(25%)
VIM-21 (gas)	**216**	—	n/a	**54**	—	n/a
LLA-23 (oil)	**939**	1,290	(27%)	**1,131**	1,652	(32%)
Ecuador (tariff oil)	**1,183**	1,631	(27%)	**1,406**	1,704	(17%)
Other (oil)	**886**	695	27%	**778**	656	19%
Total production	**17,577**	17,728	(1%)	**17,080**	15,942	7%
Inventory movements and other	**(195)**	(85)	130%	**(111)**	(92)	20%
Total sales	**17,382**	17,643	(1%)	**16,969**	15,849	7%
Sales (boepd)						
Esperanza (gas)	**10,992**	8,051	37%	**10,215**	7,325	39%
VIM-5 (gas)	**3,171**	5,935	(47%)	**3,379**	4,505	(25%)
VIM-21 (gas)	**216**	—	n/a	**54**	—	n/a
LLA-23 (oil)	**942**	1,313	(28%)	**1,135**	1,651	(31%)
Ecuador (tariff oil)	**1,183**	1,631	(27%)	**1,406**	1,704	(17%)
Other (oil)	**878**	713	23%	**780**	664	17%
Total sales	**17,382**	17,643	(1%)	**16,969**	15,849	7%
Realized Contractual Sales (boepd)						
Esperanza (gas)	**10,992**	8,051	37%	**10,215**	7,325	39%
VIM-5 (gas)	**3,171**	5,935	(47%)	**3,379**	4,505	(25%)
VIM-21 (gas)	**216**	—	n/a	**54**	—	n/a
Take-or-pay volumes	**571**	667	(14%)	**477**	527	(9%)
Total natural gas	**14,950**	14,653	2%	**14,125**	12,357	14%
Total Colombia oil	**1,820**	2,026	(10%)	**1,915**	2,315	(17%)
Ecuador tariff oil	**1,183**	1,631	(27%)	**1,406**	1,704	(17%)
Total realized contractual sales	**17,953**	18,310	(2%)	**17,446**	16,376	7%

The overall decrease in production volumes in the three months ended December 31, 2017, compared to the same period in 2016, is primarily due to production declines at LLA-23 and Ecuador, offset by an increase in gas production in Esperanza and VIM-5, as a result of the additional sales related to the Promigas pipeline expansion.

The overall increase in the production volumes in the year ended December 31, 2017, compared to the same period in 2016, is primarily due to an increase in gas production in Esperanza and VIM-5, as a result of the additional sales related to the Promigas pipeline expansion, offset by production declines at LLA-23 and Ecuador.

Canacol's ownership of its infrastructure continues to allow the Corporation to control production levels at its fields from wellhead to the sales delivery point and enables the Corporation to quickly respond to changing conditions and thereby maximize profitability.

Realized contractual gas sales during three months ended December 31, 2017 averaged approximately 85 MMscfpd.

Petroleum and Natural Gas Revenues

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Esperanza	**$ 28,783**	$ 22,762	26%	**$ 107,741**	$ 84,085	28%
VIM-5	**7,775**	16,434	(53%)	**33,663**	52,269	(36%)
VIM-21	**575**	—	n/a	**575**	—	n/a
LLA-23	**4,502**	4,930	(9%)	**18,638**	19,440	(4%)
Other	**4,140**	2,594	60%	**12,873**	8,055	60%
Petroleum and natural gas revenues, before royalties	**45,775**	46,720	(2%)	**173,490**	163,849	6%
Royalties	**(5,046)**	(6,719)	(25%)	**(19,544)**	(21,944)	(11%)
Petroleum and natural gas revenues, after royalties	**40,729**	40,001	2%	**153,946**	141,905	8%
Take-or-pay natural gas income	**1,363**	1,966	(31%)	**4,962**	6,080	(18%)
Total petroleum and natural gas revenues, after royalties, as reported	**42,092**	41,967	—	**158,908**	147,985	7%
Ecuador tariff and other revenues (1)	**4,193**	5,976	(30%)	**20,617**	25,199	(18%)
Adjusted petroleum and natural gas revenues, after royalties (1)	**$ 46,285**	$ 47,943	(3%)	**$ 179,525**	$ 173,184	4%

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

The Corporation has three types of natural gas sales:

1) *Natural Gas sales* - represents natural gas production less a typically small amount of gas volume that is consumed at the field level;

2) *Take-or-pay income* - represents the portion of natural gas sales nominations by the Corporation's off-takers that do not get delivered, typically due to the off-taker's inability to accept such gas and for which the off-takers have no recourse or legal right to delivery at a later date. As such, they are recorded as revenue in the period;

3) *Undelivered gas nominations* - represents the portion of undelivered natural gas sales nominations for which the off-takers have a legal right to take delivery at a later date, for a fixed period of time ("make-up rights"). These nominations are paid for at the time, alongside gas sales and take-or-pay income, and as such are included in deferred income for the period. The Corporation recognizes revenues associated with such make-up rights ("settlements") at the earlier of: a) when the make-up volume is delivered; b) the make-up right expires; or c) when it is determined that the likelihood that the off-taker will utilize the make-up right is remote.

During the three months and year ended December 31, 2017, the Corporation has realized $1.4 million and $5 million of take-or-pay income (as described in (2) above), which is equivalent to 571 boepd and 622 boepd of gas sales, respectively, without actual delivery of the natural gas.

As at December 31, 2017, the Corporation has received proceeds for crude oil and natural gas to be delivered at a later date (as described in (3) above). As at December 31, 2017, undelivered nominations resulted in a deferred income balance of $4.8 million ($4.4 million related to gas; $0.4 million related to crude oil) and has been classified as a current liability as it is expected to be settled within the next twelve months.

Average Benchmark and Realized Sale Prices

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Brent ($/bbl)	**$ 60.97**	$ 50.81	20%	**$ 54.28**	$ 44.45	22%
West Texas Intermediate ($/bbl)	**$ 55.43**	$ 50.19	10%	**$ 50.78**	$ 44.66	14%
Natural gas ($/boe)	**$ 28.06**	$ 30.46	(8%)	**$ 28.50**	$ 31.49	(9%)
Crude oil ($/boe)	**$ 51.61**	$ 40.37	28%	**$ 45.08**	$ 32.45	39%
Ecuador tariff ($/boe)	**$ 38.54**	$ 38.54	—	**$ 38.54**	$ 38.54	—
Esperanza ($/boe)	**$ 28.46**	$ 30.73	(7%)	**$ 28.90**	$ 31.36	(8%)
VIM-5 ($/boe)	**26.65**	30.10	(11%)	**27.29**	31.70	(14%)
VIM-21 ($/boe)	**28.92**	—	n/a	**28.92**	—	n/a
LLA-23 ($/bbl)	**51.95**	40.82	27%	**44.99**	32.17	40%
Ecuador ($/bbl)	**38.54**	38.54	—	**38.54**	38.54	—
Other ($/bbl)	**51.25**	39.55	30%	**45.22**	33.15	36%
Average realized sale price ($/boe) [1]	**$ 31.25**	$ 32.35	(3%)	**$ 31.20**	$ 32.39	(4%)

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

The increase in average realized crude oil sale prices in the three months and year ended December 31, 2017, compared to the same periods in 2016, is mainly due to increased benchmark crude oil prices.

The decrease in average realized natural gas sales prices in the three months and year ended December 31, 2017, compared to the same periods in 2016, is due to: a) the decrease in the Guajira price in December 2016, from $6.17/MMbtu to $4.63/MMbtu, and b) lower spot market prices, due to unusual seasonal conditions along Colombia's Caribbean coast negatively impacting the price relating to interruptible contracts, which represent a small portion of the Corporation's gas sales portfolio. The Guajira price is the local natural gas reference price in Colombia, which approximately 16 MMscfpd of the Corporation's natural gas production is linked to.

Royalties

	Three months ended December 31,		Year ended December 31,	
	2017	2016	**2017**	2016
Esperanza	**$ 2,497**	$ 1,886	**$ 9,394**	$ 7,315
VIM-5	**1,625**	3,543	**6,941**	11,288
VIM-21	**54**	—	**54**	—
LLA-23	**493**	518	**2,052**	2,133
Other	**377**	772	**1,103**	1,208
Total royalties	**$ 5,046**	$ 6,719	**$ 19,544**	$ 21,944

In Colombia, light crude oil and natural gas royalties are generally at a rate of 8% and 6.4%, respectively, until net field production reaches 5,000 boepd, at which time the royalty rates increase on a sliding scale to 20% up to field production of 125,000 boepd. The Corporation's LLA-23 and VMM-2 blocks are subject to an additional x-factor royalty of 3% on net revenue (effectively 2.76%). Crude oil royalties in Labrador and Rancho Hermoso are taken in kind. There are no royalties on tariff production in Ecuador. The Corporation's Esperanza natural gas production is subject to an additional overriding royalty of 2% and the Corporation's VIM-5 natural gas production is subject to an additional x-factor royalty of 13% and an overriding royalty of 3% to 4%. Royalties are calculated from revenue net of transportation expenses.

Production and Transportation Expenses

Total production and transportation expenses were as follows:

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Production expenses	**$ 7,680**	$ 6,123	25%	**$ 25,040**	$ 18,459	36%
Transportation expenses	**2,311**	712	225%	**5,243**	2,917	80%
Total production and transportation expenses	**$ 9,991**	$ 6,835	46%	**$ 30,283**	$ 21,376	42%
$/boe	**$ 6.25**	$ 4.21	48%	**$ 4.89**	$ 3.69	33%

An analysis of production expenses is provided below:

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Esperanza	**$ 3,066**	$ 1,356	126%	**$ 7,846**	$ 3,977	97%
VIM-5	**955**	884	8%	**3,442**	1,931	78%
VIM-21	**49**	—	n/a	**49**	—	n/a
LLA-23	**2,229**	2,049	9%	**7,681**	7,892	(3%)
Other	**1,381**	1,834	(25%)	**6,022**	4,659	29%
Total production expenses	**$ 7,680**	$ 6,123	25%	**$ 25,040**	$ 18,459	36%
$/boe						
Esperanza	**$ 3.03**	$ 1.83	66%	**$ 2.10**	$ 1.48	42%
VIM-5	**$ 3.27**	$ 1.62	102%	**$ 2.79**	$ 1.17	138%
VIM-21	**$ 2.46**	$ —	n/a	**$ 2.46**	$ —	n/a
Total natural gas	**$ 3.09**	$ 1.74	78%	**$ 2.27**	$ 1.36	67%
LLA-23	**$ 25.72**	$ 16.96	52%	**$ 18.54**	$ 13.06	42%
Total	**$ 4.80**	$ 3.77	27%	**$ 4.04**	$ 3.18	27%

Total natural gas production expenses per boe increased by 78% and 67% to $3.09/boe ($0.54/Mcf) and $2.27/boe ($0.40/Mcf) for the three months and year ended December 31, 2017, compared to $1.74/boe ($0.31/Mcf) and $1.36/boe ($0.24/Mcf) for the same periods in 2016, respectively. The increase is mainly attributable to: a) the operating lease cost of the Promisol Jobo gas processing facility (Jobo 2) at a contracted rate of approximately $0.57/boe ($0.10/Mcf) at the Corporation's current production level, b) expenses associated with scheduled maintenance and c) fixed level operating expenses at the new Nispero, Trombon and Toronja fields, which are anticipated to decrease on a per Mcf basis in 2018.

Production expenses per barrel at LLA-23 have increased 52% and 42% for the three months and year ended December 31, 2017, compared to the same periods in 2016, respectively, primarily due to fixed costs over lower production base.

The Corporation does not pay production expenses in Ecuador, and as such, its tariff price of $38.54 equals netback.

An analysis of transportation expenses is provided below:

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Esperanza	**$ 1,249**	$ —	n/a	**$ 2,062**	$ —	n/a
VIM-5	**566**	—	n/a	**1,578**	—	n/a
VIM-21	**260**	—	n/a	**260**	—	n/a
LLA-23	**35**	576	(94%)	**620**	2,136	(71%)
Other	**201**	136	48%	**723**	781	(7%)
Total transportation expenses	**$ 2,311**	$ 712	225%	**$ 5,243**	$ 2,917	80%
$/boe						
Esperanza	**$ 1.24**	$ —	n/a	**$ 0.55**	$ —	n/a
VIM-5	**$ 1.94**	$ —	n/a	**$ 1.28**	$ —	n/a
VIM-21	**$ 13.08**	$ —	n/a	**$ 13.08**	$ —	n/a
Total natural gas	**$ 1.57**	$ —	n/a	**$ 0.73**	$ —	n/a
LLA-23	**$ 0.40**	$ 4.77	(92%)	**$ 1.50**	$ 3.53	(58%)
Total	**$ 1.45**	$ 0.44	230%	**$ 0.85**	$ 0.50	70%

In July 2017, the Corporation entered into two interruptible gas sales contracts. The interruptible gas sales contracts have an integrated sales price whereby the Corporation is responsible for delivering the natural gas to the off-takers at Cartagena. As a result of the interruptible gas sales contracts, total natural gas transportation expense of $1.8 million and $3.6 million was recorded during the three months and year ended December 31, 2017, respectively. These interruptible gas sales contracts had combined sales of 1,527 boepd (8.7 MMscfpd) and 3,111 boepd (17.7 MMscfpd) during the three months ended and year ended December 31, 2017, respectively.

During the three months ended December 31, 2017, the Sabanas Flowline was commissioned and the Corporation delivered an average of 127 boepd (2.1 MMscfpd) through the Sabanas Flowline during the fourth quarter of 2017, resulting in total natural gas transportation expense net of the Corporation's 25.6% working interest of $0.2 million.

Transportation expenses at LLA-23 decreased 94% and 71% in the three months and year ended December 31, 2017, compared to the same periods in 2016, due to a 27% and 32% decrease in production, respectively, and more sales at the well head where the purchasers assume the transportation costs, thereby reducing transportation expenses while also decreasing the average realized sales prices as a result.

Operating Netbacks

	Three months ended December 31,			Year ended December 31,		
$/boe	**2017**	2016	Change	**2017**	2016	Change
Corporate						
Petroleum and natural gas revenues	**$ 31.25**	$ 32.35	(3%)	**$ 31.20**	$ 32.39	(4%)
Royalties	**(3.16)**	(4.14)	(24%)	**(3.16)**	(3.78)	(16%)
Production expense	**(4.80)**	(3.77)	27%	**(4.04)**	(3.18)	27%
Transportation expense	**(1.45)**	(0.44)	230%	**(0.85)**	(0.50)	70%
Operating netback [1]	**$ 21.84**	$ 24.00	(9%)	**$ 23.15**	$ 24.93	(7%)

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

Operating netbacks by major production categories were as follows:

Natural gas

$/boe	Three months ended December 31, 2017	2016	Change	Year ended December 31, 2017	2016	Change
Esperanza						
Natural gas revenues	**$ 28.46**	$ 30.73	(7%)	**$ 28.90**	$ 31.36	(8%)
Royalties	**(2.47)**	(2.55)	(3%)	**(2.52)**	(2.73)	(8%)
Production expense	**(3.03)**	(1.83)	66%	**(2.10)**	(1.48)	42%
Transportation expense	**(1.24)**	—	n/a	**(0.55)**	—	n/a
Operating netback	**$ 21.72**	$ 26.35	(18%)	**$ 23.73**	$ 27.15	(13%)
VIM-5						
Natural gas revenues	**$ 26.65**	$ 30.10	(11%)	**$ 27.29**	$ 31.70	(14%)
Royalties	**(5.57)**	(6.49)	(14%)	**(5.63)**	(6.85)	(18%)
Production expense	**(3.27)**	(1.62)	102%	**(2.79)**	(1.17)	138%
Transportation expense	**(1.94)**	—	n/a	**(1.28)**	—	n/a
Operating netback	**$ 15.87**	$ 21.99	(28%)	**$ 17.59**	$ 23.68	(26%)
VIM 21						
Natural gas revenues	**$ 28.92**	$ —	n/a	**$ 28.92**	$ —	n/a
Royalties	**(2.72)**	—	n/a	**(2.72)**	—	n/a
Production expense	**(2.46)**	—	n/a	**(2.46)**	—	n/a
Transportation expense	**(13.08)**	—	n/a	**(13.08)**	—	n/a
Operating netback	**$ 10.66**	$ —	n/a	**$ 10.66**	$ —	n/a
Total Natural Gas						
Natural gas revenues	**$ 28.06**	$ 30.46	(8%)	**$ 28.50**	$ 31.49	(10%)
Royalties	**(3.16)**	(4.22)	(25%)	**(3.29)**	(4.30)	(23%)
Production expense	**(3.09)**	(1.74)	78%	**(2.27)**	(1.36)	67%
Transportation expense	**(1.57)**	—	n/a	**(0.73)**	—	n/a
Operating netback	**$ 20.24**	$ 24.50	(17%)	**$ 22.21**	$ 25.83	(14%)

Crude Oil

$/boe	Three months ended December 31, 2017	2016	Change	Year ended December 31, 2017	2016	Change
LLA-23						
Crude oil revenues	**$ 51.95**	$ 40.82	27%	**$ 44.99**	$ 32.17	40%
Royalties	**(5.69)**	(4.29)	33%	**(4.95)**	(3.53)	40%
Production expense	**(25.72)**	(16.96)	52%	**(18.54)**	(13.06)	42%
Transportation expense	**(0.40)**	(4.77)	(92%)	**(1.50)**	(3.53)	(58%)
Operating netback	**$ 20.14**	$ 14.80	36%	**$ 20.00**	$ 12.05	66%
Ecuador						
Tariff revenues (1)	**$ 38.54**	$ 38.54	—	**$ 38.54**	$ 38.54	—
Operating netback	**$ 38.54**	$ 38.54	—	**$ 38.54**	$ 38.54	—

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

General and Administrative Expenses

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Gross costs	**$ 9,797**	$ 10,466	(6%)	**$ 29,935**	$ 25,491	17%
Less: capitalized amounts	**(796)**	(1,639)	(51%)	**(3,428)**	(3,931)	(13%)
General and administrative expenses	**$ 9,001**	$ 8,827	2%	**$ 26,507**	$ 21,560	23%
$/boe	**$ 5.63**	$ 5.44	3%	**$ 4.28**	$ 3.72	15%

Gross general and administrative expenses ("G&A") decreased by 6% in the three months ended December 31, 2017, compared to same period in 2016, primarily due to less personnel costs incurred. Similar to the fourth quarter of 2016, the final quarter of 2017 reported higher G&A than the first three quarters of the year primarily due to year-end audit costs, bonuses and other similar annual expenses.

Gross general and administrative expenses ("G&A") increased by 17% in the year ended December 31, 2017, compared to same period in 2016, primarily due to increased costs in preparation for significantly increased gas production and internal reorganization costs during the year.

Net Finance Income and Expense

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Net financing expense paid	**$ 4,152**	$ 4,573	(9%)	**$ 21,216**	$ 17,346	22%
Non-cash financing costs	**1,404**	1,325	6%	**9,474**	5,323	78%
Net finance expense	**$ 5,556**	$ 5,898	(6%)	**$ 30,690**	$ 22,669	35%

On February 14, 2017, the Corporation entered into a credit agreement for a $265 million senior secured term loan with a syndicate of banks led by Credit Suisse (the "2017 Senior Secured Term Loan"). The 2017 Senior Secured Term Loan agreement also allowed an additional $40 million of greenshoe funds available to be drawn at any time within 12 months post-funding at the sole discretion of the Corporation, subject to certain conditions, all of which were drawn during the year ended December 31, 2017.

Proceeds from the 2017 Senior Secured Term Loan was used for the repayment of the principal in the amount of $255 million including $180 million of the BNP Senior Secured Term Loan and $75 million of Senior Notes, plus accrued interest and costs of the transaction. The carrying value of the BNP Senior Secured Term Loan and Senior notes included $4.4 million of transaction costs netted against the principal amounts, which were fully expensed at the time of settlement and included in net finance expense of $30.7 million reported in 2017.

Hedging Contract

During the year ended December 31, 2017, the Corporation entered into a hedging contract under the following terms:

Term	Principal	Type	Interest Rate Range
Aug 2017 - Jun 2019	$305 million	LIBOR collar	1.4% - 2.5%

(Gains) losses on hedging contracts recognized in the net income (loss) and comprehensive gain (loss) are summarized below:

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Hedging contract - unrealized	**$ (186)**	$ (3)	>999%	**$ (35)**	$ —	n/a
Hedging contract - realized	**58**	—	n/a	**156**	—	n/a

Stock Based Compensation Expense and Restricted Share Units

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Stock-based compensation expense	**$ 962**	$ 1,002	(4%)	**$ 7,673**	$ 6,458	19%
Restricted share unit expense	**—**	62	(100%)	**3,913**	3,189	23%
Stock-based compensation and restricted share unit expense	**$ 962**	$ 1,064	(10%)	**$ 11,586**	$ 9,647	20%

Stock-based compensation and restricted share units expense is a non-cash expense recognized based on the fair value of units granted. The fair value of the stock options granted were estimated using the Black-Scholes option pricing model.

Depletion and Depreciation Expense

	Three months ended December 31,			Year ended December 31,		
	2017	2016	Change	**2017**	2016	Change
Depletion and depreciation expense	**$ 10,060**	$ 6,193	62%	**$ 35,776**	$ 26,512	35%
$/boe	**$ 6.29**	$ 3.82	65%	**$ 5.78**	$ 4.57	26%

Depletion and depreciation expense increased 62% and 35% in the three months and year ended December 31, 2017, compared to the same periods in 2016, respectively, primarily as a result of a higher depletable base.

Assets and Liabilities Held for Sale

Ecuador IPC Joint Venture

As at December 31, 2017	**Carrying amount**	**Impairment loss**	**Recoverable amount**
Assets held for sale			
Restricted cash	$ 30,719	$ 8,052	$ 22,667
Investment in equity	17,212	11,772	5,440
	$ 47,931	**$ 19,824**	**$ 28,107**

The Corporation has classified its 25% equity interest in the Ecuador IPC and related term deposits used as collateral to secure the Ecuador IPC's borrowings ("Ecuador restricted cash") as assets held for sale as at December 31, 2017, due its commitment to sell its equity interest in the Ecuador IPC, which closed subsequent to December 31, 2017. Proceeds for the sale total $36.4 million, consisting of $28.1 million of cash proceeds and $8.3 million return of an outstanding term deposit which has been classified as current restricted cash as at December 31, 2017. A portion of the total proceeds ($30.8 million) has been received in January 2018 and the remaining $6 million will be received in June 2019. As a result of being classified as assets held for sale, the carrying amounts of the investment in the Ecuador IPC and Ecuador restricted cash were revalued to the lower of their carrying value and fair value less cost to sell of $28.1 million, resulting in an impairment loss of $19.8 million.

Petroleum Assets and Liabilities

As at December 31, 2017	**Carrying amount**	**Impairment loss**	**Recoverable amount**
Assets held for sale			
Petroleum assets	**$ 146,539**	**$ 102,686**	**$ 43,853**

	Carrying amount	**Revaluation gain**	**Recoverable amount**
Liabilities held for sale			
Decommissioning obligations	$ 7,694	$ (4,934)	$ 2,760
Other long term obligations	1,094	—	1,094
	$ 8,788	**$ (4,934)**	**$ 3,854**

The Corporation has classified certain petroleum assets as held for sale as at December 31, 2017, due to its intention to sell the assets, which is expected to be completed in 2018. As at December 31, 2017, the assets and liabilities were revalued to the lower of their carrying amounts and fair value less cost to sell, resulting in a net impairment loss of $97.8 million.

Income Tax Expense

	Three months ended December 31,				Year ended December 31,			
		2017		2016		**2017**		2016
Current income tax expense	$	**5,888**	$	(6,256)	$	**25,857**	$	16,079
Deferred income tax expense (recovery)		**13,162**		(42,347)		**6,590**		(50,162)
Income tax expense (recovery)	$	**19,050**	$	(48,603)	$	**32,447**	$	(34,083)

The Corporation's pre-tax income was subject to the Colombian statutory income tax rate of 40% for the year ended December 31, 2017. The Colombian statutory income tax rate has decreased to 37% on January 1, 2018 and will further decrease to 33% on January 1, 2019. At December 31, 2017, the Corporation had non-capital losses carried forward of approximately $134.1 million available to reduce future years taxable income.

Cash and Funds from Operations and Net Income (Loss) and Comprehensive Income (Loss)

	Three months ended December 31,					Year ended December 31,				
		2017		2016	Change		**2017**		2016	Change
Cash flow provided by operating activities	$	**25,001**	$	30,289	(17%)	$	**65,346**	$	73,577	(11%)
Per share – basic	$	**0.14**	$	0.17	(18%)	$	**0.37**	$	0.44	(16%)
Per share – diluted	$	**0.14**	$	0.17	(18%)	$	**0.37**	$	0.44	(16%)
Adjusted funds from operations [(1)]	$	**20,857**	$	41,979	(50%)	$	**84,804**	$	113,019	(25%)
Per share – basic	$	**0.12**	$	0.24	(50%)	$	**0.48**	$	0.68	(29%)
Per share – diluted	$	**0.12**	$	0.24	(50%)	$	**0.48**	$	0.67	(28%)
Net income (loss) and comprehensive income (loss)	$	**(150,343)**	$	20,331	n/a	$	**(148,029)**	$	23,638	n/a
Per share – basic	$	**(0.85)**	$	0.12	n/a	$	**(0.85)**	$	0.14	n/a
Per share – diluted	$	**(0.85)**	$	0.12	n/a	$	**(0.85)**	$	0.14	n/a

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

Capital Expenditures

	Three months ended December 31,		Year ended December 31,	
	2017	2016	**2017**	2016
Drilling and completions	**$ 15,052**	$ 16,553	**$ 40,113**	$ 35,864
Facilities, work overs and infrastructure	**27,445**	37,397	**36,949**	48,900
Sabanas Flowline costs	**(14,083)**	—	**10,524**	—
Land, seismic, communities and other	**3,592**	10,719	**25,744**	24,053
Non-cash costs and adjustments(2)	**9,646**	(6,003)	**7,872**	(12,320)
Property acquisition	**—**	—	**—**	11,483
Dispositions and farm-outs	**—**	(28)	**—**	(50)
Net capital expenditures	**41,652**	58,638	**121,202**	107,930
Ecuador	**2,721**	1,053	**4,205**	2,294
Adjusted net capital expenditures (1)	**$ 44,373**	$ 59,691	**$ 125,407**	$ 110,224
Net capital expenditures recorded as:				
Expenditures on exploration and evaluation assets	**$ 14,338**	$ 12,062	**$ 51,919**	$ 36,510
Expenditures on property, plant and equipment	**27,314**	46,604	**69,283**	59,987
Property acquisition	**—**	—	**—**	11,483
Dispositions and farm-outs	**—**	(28)	**—**	(50)
Net capital expenditures	**$ 41,652**	$ 58,638	**$ 121,202**	$ 107,930

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.
(2) Other non-cash costs incurred in 2017 include capitalized costs related to decommissioning liabilities and a finance lease obligation relating to the first compression station connecting to the Sabanas Flowline.

Capital expenditures in the three months ended December 31, 2017 primarily related to:

- Drilling costs at Esperanza (Canandonga-1);
- Drilling costs at VIM-5 (Pandereta-1 and Pandereta-2);
- Facility costs at Esperanza and VIM-5;
- Liquefied natural gas plant purchase;
- Sabanas Flowline costs net of funds received from private investment;
- Facility costs related to the Ecuador IPC (accounted for under the equity method of accounting); and
- Other capitalized costs (capitalized G&A of $0.8 million).

The Corporation entered into the Sabanas Flowline agreement during the year ended December 31, 2017. Pursuant to the agreement, financing of the project consists of $30.5 million investment from a group of private investors ("private investment") and a $10.5 million contribution from the Corporation, with each holding its interest in the Sabanas Flowline in separate companies, resulting in a joint operation. During the three months ended December 31, 2017, the Corporation received $22.9 million of the $30.5 million private investment, resulting in net capital expenditure recovery of $14.1 million. As at December 31, 2017, the Corporation has a receivable of $7.6 million for the remaining private investment, all of which was collected subsequent to December 31, 2017.

LIQUIDITY AND CAPITAL RESOURCES

Capital Management

The Corporation's policy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain investor, creditor and market confidence. The Corporation manages its capital structure and makes adjustments in response to changes in economic conditions and the risk characteristics of the underlying assets. The Corporation considers its capital structure to include share capital, bank debt, finance leases and working capital, defined as current assets less current liabilities. In order to maintain or adjust the capital structure, from time to time the Corporation may issue common shares or other securities, sell assets or adjust its capital spending to manage current and projected debt levels.

The Corporation monitors leverage and adjusts its capital structure based on its net debt level. Net debt is defined as the principal amount of its outstanding bank debt, finance lease obligations, less working capital, as defined above. In order to facilitate the management of its net debt, the Corporation prepares annual budgets, which are updated as necessary depending on varying factors including current and forecast crude oil prices, changes in capital structure, execution of the Corporation's business plan and general industry conditions. The annual budget is approved by the Board of Directors and updates are prepared and reviewed as required.

At December 31, 2017, the Corporation had $39 million of unrestricted cash. As at March 23, 2018, having collected all of the Sabanas Flowline funds from the private investors, as described above, and the Ecuador sale proceeds, the Corporation has approximately $70 million in unrestricted cash.

During the year ended December 31, 2017, the Corporation sold 11.9 million of the 16.2 million investment in shares of Interoil Exploration and Production ASA ("Interoil") for proceeds of $5.1 million. Subsequent to December 31, 2017, the Corporation has sold its remaining shares of Interoil for proceeds of $1.9 million, resulting in an overall realized cash gain of $3.8 million on the Corporation's original $3.2 million investment.

The funds from the 2017 Senior Secured Term Loan were used to retire the Corporation's existing bank loan of $255 million. The Senior Secured Term Loan also has the following benefits: a) a lower the average interest rate, and b) extended the first amortization payment of the new term loan into 2019.

		December 31, 2017
Bank debt – principal	$	305,000
Finance lease obligations		35,858
Working capital surplus		(110,401)
Net debt	$	230,457

On February 14, 2017, the Corporation entered into a credit agreement for a $265 million senior secured term loan with a syndicate of banks led by Credit Suisse (the "2017 Senior Secured Term Loan"). The 2017 Senior Secured Term Loan will mature on March 20, 2022, with interest payable quarterly and principal repayable in 13 equal quarterly installments starting March 20, 2019, following more than two years of initial grace period. The 2017 Senior Secured Term Loan carries interest at LIBOR plus 5.5% and is secured by all of the material assets of the Corporation. Proceeds from the 2017 Senior Secured Term Loan were used for the repayment of the principal in the amount of $255 million including $180 million of the BNP Senior Secured Term Loan and $75 million of Senior Notes, plus accrued interest and costs of the transaction. The carrying value of the BNP Senior Secured Term Loan and Senior notes included $4.4 million of transaction costs netted against the principal amounts, which were fully expensed at the time of settlement. The carrying value of the 2017 Senior Secured Term Loan included $10.4 million of transaction costs netted against the principal amounts as at December 31, 2017. The 2017 Senior Secured Term Loan agreement also allowed an additional $40 million of greenshoe funds available to be drawn at any time within 12 months post-funding at the sole discretion of the Corporation, subject to certain conditions, all of which were drawn during the year ended December 31, 2017.

The 2017 Senior Secured Term Loan includes various non-financial covenants and financial covenants, including a maximum consolidated leverage ratio ("Consolidated Leverage Ratio") of 3.00:1.00, a minimum consolidated interest coverage ratio ("Consolidated Interest Coverage Ratio") of 3.50:1.00, a minimum consolidated current assets to consolidated current liabilities ratio ("Consolidated Current Assets to Consolidated Current Liabilities Ratio") of 1.00:1.00, a minimum PV10 ratio of 1.30:1.00 and a minimum debt service coverage ratio of 1.50:1.00.

The Consolidated Leverage Ratio is calculated on a quarterly basis as consolidated total debt ("Consolidated Total Debt") divided by consolidated EBITDAX ("Consolidated EBITDAX"). Consolidated Total Debt includes the principal amount of all indebtedness, which currently includes bank debt and finance lease obligation; additionally, restricted cash maintained in the debt service reserve account related to the 2017 Senior Secured Term Loan is deductible against Consolidated Total Debt. Consolidated EBITDAX is calculated on a rolling 12-month basis and is defined as consolidated net income (loss) adjusted for interest, income taxes, depreciation, depletion, amortization, exploration expenses, equity income (loss) and other similar non-recurring or non-cash charges. Consolidated EBITDAX is further adjusted for the Corporation's share of revenues from the Ecuador IPC, to the extent that they are collected in cash since the investment is accounted for using the equity method in the Corporation's financial statements and impacts the consolidated funds from operations.

The Consolidated Interest Coverage Ratio is calculated on a quarterly basis as Consolidated EBITDAX divided by consolidated interest expense ("Consolidated Interest Expense"). Consolidated EBITDAX is calculated on a rolling 12-month basis as described in the above paragraph. Consolidated Interest Expense is calculated on a rolling 12-month basis and excludes non-cash interest charges.

The Consolidated Current Assets to Consolidated Current Liabilities Ratio is calculated on a quarterly basis as consolidated current assets divided by consolidated current liabilities, excluding the current portion of any long-term indebtedness and any non-cash current assets and non-cash current liabilities.

The PV10 ratio is calculated semi-annually as the present value of after-tax future net revenues of the Corporation's proved reserves discounted at 10% calculated from the Corporation's reserves reports divided by the outstanding principal balance of the 2017 Senior Secured Term Loan.

The debt service coverage ratio is calculated on a quarterly basis as the ratio of: a) the aggregate amount of cash received in the Corporation's collection accounts during the quarter to b) the upcoming debt service amount.

Consolidated Total Debt and Consolidated EBITDAX are calculated as follows:

Consolidated Total Debt		**December 31, 2017**
Bank debt – principal	$	305,000
Finance lease obligations		35,858
Liquefied natural gas plant purchase financing		9,500
Debt service reserve account balance		(15,320)
Consolidated Total Debt	$	335,038

Consolidated EBITDAX	**Q1**	**Q2**	**Q3**	**Q4**	**Rolling**
Consolidated net income (loss)	(7,942)	11,770	(1,514)	(150,343)	(148,029)
(+) Interest expense	6,405	6,221	6,743	4,948	24,317
(+/-) Income taxes (recovery)	3,777	11,279	(1,659)	19,050	32,447
(+) Wealth taxes	450	24	(16)	—	458
(+) Depletion and depreciation	9,797	5,539	10,380	10,060	35,776
(+) Pre-license and exploration expenses	23	23	1,069	26,017	27,132
(-) Equity (loss) profit	(286)	(493)	(268)	(1,475)	(2,522)
(+/-) Other non-cash expenses (income)	16,628	(11,016)	12,869	117,407	135,888
(+) Contribution of Ecuador IPC	5,392	5,724	5,308	4,193	20,617
Consolidated EBITDAX	34,244	29,071	32,912	29,857	126,084
(+/-) Ecuador IPC receivable adjustment	(5,392)	13,751	(5,308)	1,057	4,108
Covenant EBITDAX	28,852	42,822	27,604	30,914	130,192

Consolidated Leverage Ratio		**December 31, 2017**
Consolidated Total Debt	$	335,038
Consolidated EBITDAX		130,192
Consolidated Leverage Ratio		2.57

The Consolidated Interest Coverage Ratio is calculated as follows:

Consolidated Interest Coverage Ratio		**December 31, 2017**
Consolidated Interest Expense	$	24,317
Consolidated EBITDAX		130,192
Consolidated Interest Coverage Ratio		5.35

The Corporation was in compliance with its covenants as at December 31, 2017.

Letters of Credit

At December 31, 2017, the Corporation had letters of credit outstanding totaling $81.3 million to guarantee work commitments on exploration blocks in Colombia and to guarantee other contractual commitments, of which $21.1 million relates to assets held for sale.

At March 23, 2018, the Corporation had 176.8 million common shares, 16.3 million stock options and 0.6 million restricted share units outstanding.

CONTRACTUAL OBLIGATIONS

The following table provides a summary of the Corporation's cash requirements to meet its financial liabilities and contractual obligations existing at December 31, 2017:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	$ —	$ 187,692	$ 117,308	$ 305,000
Finance lease obligations - undiscounted (1)	9,391	18,966	19,849	48,206
Trade and other payables	59,739	—	—	59,739
Crude oil payable in kind	748	—	—	748
Taxes payable	8,663	—	—	8,663
Deferred income	4,805	—	—	4,805
Other long term obligations	—	—	1,903	1,903
Restricted share units	1,971	32	—	2,003
Exploration and production contracts	21,511	49,805	22,016	93,332
Jobo facility operating contract	2,879	5,757	2,638	11,274
Compression station lease contracts (2)	4,034	7,830	37,799	49,663
Office leases	1,447	1,403	1,157	4,007

(1) The finance lease obligations comprise of Jobo natural gas processing facility ($30.6 million) and the first Sabanas compression station ($17.6 million).

(2) The compression station lease contract comprises of the operating contract for the first Sabanas compression station and the total lease contract (operating and capital components) of the second Sabanas compression station. The second Sabanas compression station commenced operation in February 2018 and the capital portion of the lease contract will be recorded as a finance lease.

Exploration and Production Contracts

The Corporation has entered into a number of exploration contracts in Colombia which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding exploration commitments at December 31, 2017 of $93.3 million and has issued $37.3 million in financial guarantees related thereto. The Corporation intends to sell certain petroleum E&E and D&P assets as at December 31, 2017 and as a result, $25.6 million of the total $93.3 million of the exploration commitments and $21.1 million of the $37.3 million financial guarantees relating to these assets will no longer be held by the Corporation.

Pipeline Ship-Or-Pay Contracts

The Corporation owns a 0.5% interest in Oleoducto Bicentenario de Colombia ("OBC"), which owns a pipeline system that will link Llanos basin oil production to the Cano Limon oil pipeline system. Under the terms of the OBC agreement, the Corporation may be required to provide financial support or guarantees for its proportionate equity interest in any future debt financings undertaken by OBC. The Corporation has also entered into ship-or-pay arrangements with OBC and Cenit Transporte y Logística de Hidrocarburos S.A. for 550 barrels of oil per day at a variable regulated tariff. The tariffs as at December 31, 2017 are $7.56 / barrel and $2.97 / barrel, respectively. The ship-or-pay contracts will expire in November 2025 and 2028, respectively.

OUTLOOK

Management's objectives for 2018 are to: 1) sell an average of 114 to 129 MMscfpd of gas and 1,700 bopd, 2) execute the necessary investments in drilling, facilities, and flowlines to ensure that the productive capacity of the Corporation is greater than 230 MMscfpd by December 1, 2018, 3) execute a four well exploration and appraisal drilling program to build reserves and 4) divest our non-core Colombian conventional oil assets to focus on the exploration and commercialization of our significant Colombian gas reserves and resource base.

Highlights of the capital spending program aimed at ensuring that the Corporation achieves 230 MMscfpd of gas production capability by December of 2018 include: 1) the drilling of four exploration and appraisal wells and three development wells, 2) expansion of the Corporation's gas gathering and processing facilities at Jobo, and 3) various workovers of its existing gas wells. The Corporation also expects to acquire new 3D seismic data on its VIM-5 contract to continue building its gas exploration drilling portfolio. Approximately 97% of the $80 million budget for 2018 is dedicated to spending on the Corporation's gas assets, with the remainder on its oil assets. The capital program will be fully funded from existing cash and cash flows. One of the planned appraisal wells, Pandereta-3, was spud on January 12, 2018. The Pandereta-3 appraisal well encountered 103 feet true vertical depth of net gas pay within the CDO sandstone reservoir and flow tested at an absolute open flow rate of 168 MMscfpd from the upper part of the CDO in February 2018, confirming a significant new gas discovery on the VIM-5 block. As at March 23, 2018, having collected all of the Sabanas Flowline funds from the private investors and the Ecuador sale proceeds, the Corporation has approximately $70 million in unrestricted cash.

As previously announced, forecast realized contractual gas and oil sales, which include contractual gas downtime for 2018, are anticipated to average between 21,700 and 24,300 boepd, which include 114 and 129 MMscfpd of gas, respectively, and approximately 1,700 bopd of annualized oil production. Upon a successful sale of the Colombian oil assets, this annualized oil production forecast would be revised accordingly. The base range for gas production assumes that the Promigas S.A. expansion, which will add 100 MMscfpd of transportation capacity between the Corporation's gas processing facilities located at Jobo and the markets of Cartagena and Barranquilla, is delayed and does not materialize as of December 1, 2018. The upper range for gas production assumes that the Promigas S.A. expansion is completed on December 1, 2018, as currently planned, and that the Corporation sells additional natural gas in the interruptible market throughout 2018. Based on the Corporation's current portfolio of 2018 gas contracts, the average sales price, net of transportation costs where applicable, is approximately $4.75/Mcf.

The Corporation has contracted a single drilling rig which it intends to use to execute its exploration and development drilling program for the remainder of 2018. In the first quarter of 2018, the Corporation successfully completed and tested the Pandereta-2 and Pandereta-3 appraisal wells, both of which have confirmed a significant new gas discovery on its VIM-5 contract. The remaining gas exploration wells planned for 2018 include the Breva-1 exploration well on the VIM-21 contract, and the Borojo-1 and Canahuate-Este exploration wells on the Esperanza contract. The remaining development wells are the Chirimia-1 well located on the VIM-5 contract which spud in early March 2018, and one other infill development well yet to be determined to be spud prior to mid-year 2018. The Corporation anticipates that its exploration and development drilling programs will be completed by the third quarter of 2018. The objective of the 2018 drilling program is to lift the productive potential of its existing and new well portfolio beyond the 230 MMscfpd required by December 1, 2018.

The Corporation expects to soon award a contract to build and install a new gas processing module at its Jobo gas facility to process an additional 100 MMscfpd of gas, which will raise the gas treating capability of the Jobo facility to 300 MMscfpd by December 2018. The Corporation will purchase and operate the new gas processing module.

SUMMARY OF QUARTERLY RESULTS

	2017				2016			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
Total Petroleum and natural gas revenues, net of royalties	**42,092**	37,950	37,283	41,583	41,967	44,392	38,926	22,700
Adjusted petroleum and natural gas revenues, net of royalties (1)	**46,285**	43,258	43,007	46,975	47,943	50,851	45,390	29,000
Cash flow provided by operating activities	**25,001**	11,783	11,130	17,539	30,289	22,275	13,764	7,249
Per share – basic ($)	**0.14**	0.07	0.06	0.10	0.17	0.13	0.09	0.05
Per share – diluted ($)	**0.14**	0.07	0.06	0.10	0.17	0.13	0.08	0.05
Adjusted funds from operations (1)	**20,857**	18,871	24,236	20,947	41,979	30,719	26,870	13,451
Per share – basic ($) (1)	**0.12**	0.11	0.14	0.12	0.24	0.18	0.17	0.08
Per share – diluted ($) (1)	**0.12**	0.11	0.14	0.12	0.24	0.18	0.16	0.08
Net income (loss) and comprehensive income (loss)	**(150,343)**	(1,514)	11,770	(7,942)	20,331	(8,399)	11,245	461
Per share – basic ($)	**(0.85)**	(0.01)	0.07	(0.05)	0.12	(0.05)	0.07	0.00
Per share – diluted ($)	**(0.85)**	(0.01)	0.07	(0.05)	0.12	(0.05)	0.07	0.00
Capital expenditures, net	**41,652**	24,978	30,572	24,000	58,638	28,698	5,046	15,548
Adjusted capital expenditures, net (1)	**44,373**	25,568	30,648	24,818	59,691	29,208	5,376	15,949
Operations (boepd)								
Petroleum and natural gas production, before royalties								
Petroleum (2)	**3,008**	3,263	3,487	3,505	3,616	3,892	4,018	4,526
Natural gas	**14,569**	13,324	13,675	13,487	14,112	14,740	12,405	6,407
Total (2)	**17,577**	16,587	17,162	16,992	17,728	18,632	16,423	10,933
Petroleum and natural gas sales, before royalties								
Petroleum (2)	**3,003**	3,268	3,500	3,517	3,657	3,801	4,045	4,578
Natural gas	**14,379**	13,239	13,563	13,409	13,986	14,621	12,331	6,329
Total (2)	**17,382**	16,507	17,063	16,926	17,643	18,422	16,376	10,907
Realized contractual sales, before royalties								
Natural gas	**14,950**	13,338	13,695	14,526	14,653	15,107	12,972	6,642
Colombia oil	**1,820**	1,895	1,933	2,014	2,026	2,090	2,294	2,856
Ecuador tariff oil (2)	**1,183**	1,373	1,567	1,503	1,631	1,711	1,751	1,722
Total (2)	**17,953**	16,606	17,195	18,043	18,310	18,908	17,017	11,220

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.
(2) Includes tariff oil production related to the Ecuador IPC.

RISKS AND UNCERTAINTIES

The Corporation is subject to several risk factors including, but not limited to: the volatility of oil and natural gas prices; foreign exchange and currency risks; general risks related to foreign operations such as political, economic, regulatory and other uncertainties as they relate to both foreign investment policies and energy policies; governments exercising from time to time significant influence on the economy to control inflation; developing environmental regulations in foreign jurisdictions; discovery of new oil and natural gas reserves; concentration of oil sales receipts with a few major customers; substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the long-term for which additional financings may be required to implement the Corporation's business plan. Although periodic volatility of financial and capital markets may severely limit access to capital, the Corporation has been able to successfully attract capital in the past.

The Corporation is exposed to foreign exchange and currency risk as a result of fluctuations in exchange rates through its cash deposits and investments denominated in the Colombian peso and the Canadian dollar.

Most of the Corporation's revenues and funds from financing activities are expected to be received in reference to United States dollar ("US dollar") denominated prices while a portion of its operating, capital, and general and administrative costs are denominated in Colombian Pesos and Canadian dollars. The Corporation has not entered into any currency derivatives in order to reduce its exposure to fluctuations that the US dollar may incur.

The Corporation is exposed to interest rate risk on certain variable interest rate debt instruments, to the extent they are drawn. The remainder of the Corporation's financial assets and liabilities are not exposed to interest rate risk. During the year ended December 31, 2017, the Corporation entered into a hedging contract under the following terms:

Term	Principal	Type	Interest Rate Range
Aug 2017 - Jun 2019	$305 million	LIBOR collar	1.4% - 2.5%

Fluctuations in energy prices will not only impact revenues of the Corporation but may also impact the Corporation's ability to raise capital. Commodity prices for crude oil are impacted by world economic events that dictate the levels of supply and demand. From time to time the Corporation may attempt to mitigate commodity price risk through the use of financial derivatives. The Corporation's policy is to only enter into commodity contracts considered appropriate to a maximum of 50% of forecasted production volumes. The Corporation had no commodity contracts as at or during the year ended December 31, 2017.

The Corporation's policy is to enter into agreements with customers that are well established and well-financed entities in the oil and gas industry such that the level of risk associated with one or more of its customers facing financial difficulties are mitigated while balancing factors of economic dependence with profit maximization. To date, the Corporation has not experienced any material credit loss in the collection of trade accounts receivable.

The Corporation attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The Corporation also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

A more comprehensive discussion of risks and uncertainties is contained in the Corporation's Annual Information Form for the year ended December 31, 2017 as filed on SEDAR and hereby incorporated by reference.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's management made judgements, assumptions and estimates in the preparation of the financial statements. Actual results may differ from those estimates, and those differences may be material. The basis of presentation and the Corporation's significant accounting policies can be found in the notes to the financial statements.

CHANGES IN ACCOUNTING POLICIES

The Corporation is currently reviewing a number of new and revised IFRSs that have been issued but are not yet effective. Detailed discussions of new accounting policies that may affect the Corporation are provided in the financial statements of the Corporation as at and for the year ended December 31, 2017.

REGULATORY POLICIES

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("DC&P") are designed to provide reasonable assurance that all material information is gathered and reported on a timely basis to senior management so that appropriate decisions can be made regarding public disclosure and that information required to be disclosed by the issuer under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), along with other members of management, have designed, or caused to be designed under the CEO and CFO's supervision, DC&P and have assessed the design and operating effectiveness of the Corporation's DC&P as at December 31, 2017. Based on this assessment, it was concluded that the design and operation of the Corporation's DC&P are effective as at December 31, 2017.

Internal Controls over Financial Reporting

The CEO and CFO, along with participation from other members of management, are responsible for establishing and maintaining adequate Internal Control over Financial Reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial statements prepared in accordance with IFRS. The Corporation's CEO and CFO, with support of management have assessed the design and operating effectiveness of the Corporation's ICFR as at December 31, 2017 based on criteria described in "Internal Control - Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, it was concluded that the design and operation of the Corporation's ICFR are effective as at December 31, 2017.

During the three months ended December 31, 2017, there has been no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Limitations of Controls and Procedures

The Corporation's management, including its CEO and CFO, believe that any DC&P or ICFR, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, they cannot provide absolute assurance that all control issues and instances of fraud, if any, within the Corporation have been prevented or detected. These inherent limitations include the realities that judgements in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Accordingly, because of the inherent limitations in a cost effective control system, misstatements due to error or fraud may occur and not be detected. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.