CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2017

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial	Three months ended September 30, 2017	2016	Change	Nine months ended September 30, 2017	2016	Change
Total petroleum and natural gas revenues, net of royalties	**37,950**	44,392	(15%)	**116,816**	106,018	10%
Adjusted petroleum and natural gas revenues, net of royalties[2]	**43,258**	50,851	(15%)	**133,240**	125,241	6%
Cash flow provided by operating activities	**11,783**	22,275	(47%)	**40,345**	43,288	(7%)
Per share – basic ($)	**0.07**	0.13	(46%)	**0.23**	0.27	(15%)
Per share – diluted ($)	**0.07**	0.13	(46%)	**0.23**	0.26	(12%)
Adjusted funds from operations [1][2]	**18,871**	30,719	(39%)	**63,947**	71,040	(10%)
Per share – basic ($)	**0.11**	0.18	(39%)	**0.37**	0.44	(16%)
Per share – diluted ($)	**0.11**	0.18	(39%)	**0.36**	0.43	(16%)
Net income (loss) and comprehensive income (loss)	**(1,514)**	(8,399)	(82%)	**2,314**	3,307	(30%)
Per share – basic ($)	**(0.01)**	(0.05)	(80%)	**0.01**	0.02	(50%)
Per share – diluted ($)	**(0.01)**	(0.05)	(80%)	**0.01**	0.02	(50%)
Capital expenditures, net, including acquisitions	**24,978**	28,698	(13%)	**79,550**	49,292	61%
Adjusted capital expenditures, net, including acquisitions[1][2]	**25,568**	29,208	(12%)	**81,034**	50,533	60%
				Sep 30, 2017	Dec 31, 2016	Change
Cash				**35,775**	66,283	(46%)
Restricted cash				**54,525**	62,073	(12%)
Working capital surplus				**62,168**	64,899	(4%)
Bank debt				**294,195**	250,638	17%
Total assets				**799,307**	787,508	1%
Common shares, end of period (000's)				**175,927**	174,359	—

Operating	Three months ended September 30, 2017	2016	Change	Nine months ended September 30, 2017	2016	Change
Petroleum and natural gas production, before royalties (boepd)						
Petroleum [3]	**3,263**	3,892	(16%)	**3,418**	4,145	(18%)
Natural gas	**13,324**	14,740	(10%)	**13,495**	11,197	21%
Total [2]	**16,587**	18,632	(11%)	**16,913**	15,342	10%
Petroleum and natural gas sales, before royalties (boepd)						
Petroleum [3]	**3,268**	3,801	(14%)	**3,428**	4,141	(17%)
Natural gas	**13,239**	14,621	(9%)	**13,403**	11,106	21%
Total [2]	**16,507**	18,422	(10%)	**16,831**	15,247	10%
Realized contractual sales, before royalties (boepd)						
Natural gas	**13,338**	15,107	(12%)	**13,848**	11,586	20%
Colombia oil	**1,895**	2,090	(9%)	**1,947**	2,413	(19%)
Ecuador tariff oil [2]	**1,373**	1,711	(20%)	**1,481**	1,728	(14%)
Total [2]	**16,606**	18,908	(12%)	**17,276**	15,727	10%
Operating netbacks ($/boe) [1]						
Esperanza (natural gas)	**23.46**	27.63	(15%)	**24.46**	27.45	(11%)
VIM-5 (natural gas)	**12.96**	24.65	(47%)	**18.14**	24.52	(26%)
LLA-23 (oil)	**19.13**	13.78	39%	**19.96**	11.36	76%
Ecuador (tariff oil) [2]	**38.54**	38.54	—	**38.54**	38.54	—
Total [2]	**23.02**	25.83	(11%)	**23.60**	25.28	(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 and Ecuador. The Corporation's head office is located at 4500, 525 - 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 November 13, 2017 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 unaudited interim condensed consolidated financial statements of the Corporation for the three and nine months ended September 30, 2017 and 2016 (the "financial statements"), and the audited consolidated financial statements and management's discussion and analysis for the year ended December 31, 2016. The financial statements have been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting", 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. 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 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 reconciles the Corporation's cash provided by operating activities to adjusted funds from operations:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	**2017**	2016
Cash flow provided by operating activities	**$ 11,783**	$ 22,275	**$ 40,345**	$ 43,288
Changes in non-cash working capital	**2,093**	2,260	**7,978**	9,378
Ecuador IPC revenue, net of current income taxes	**4,995**	6,184	**15,624**	18,374
Adjusted funds from operations	**$ 18,871**	$ 30,719	**$ 63,947**	$ 71,040

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, excluding any non-cash items, 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 September 30, 2017, the Corporation's production primarily consisted of natural gas from its Nelson, Palmer and Nispero fields in the Esperanza block and Clarinete field in the VIM-5 block, both located in the Lower Magdalena Basin in Colombia, crude oil from its 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 its Rancho Hermoso, VMM-2 and Santa Isabel properties in Colombia.

During the three months ended September 30, 2017, ConocoPhillips Colombia, the operator of the Corporation's VMM-3 contract, completed their testing operations on the Picoplata-1 well. The well was designed to test the petroleum potential of shales and limestones within the Cretaceous La Luna Formation, and the well encountered over 1,200 feet ("ft") of potential oil bearing reservoirs. Since December of 2016, five discrete formation injection tests and three hydraulic stimulations spanning the entire interval have been performed in three shale reservoir intervals within the La Luna. The objective of the testing program was to collect information on the productive capability of the reservoir, the quality of the fluids contained within the reservoir, the formation pressure of the reservoir, and the ability of the reservoir to be hydraulically stimulated. The testing operation was successful with all intervals that were hydraulically stimulated and tested producing light gravity crude oil with no indication of formation water. Individual slickwater hydraulic stimulation size in vertical well sections between 27 and 30 ft thick varied between 80,000 and 346,000 pounds, with resulting natural flows averaging between 19 to 120 barrels of oil per day with no formation water, over flow periods of 3 to 28 days. The testing program achieved the objective of collecting the post stimulation production, pressure, and fluid data, as well as confirming the viability of hydraulically stimulating the reservoirs, and the Picoplata-1 well is currently being abandoned. Canacol and its partner ConocoPhillips Colombia are evaluating the technical data collected from this well to plan the next steps towards further evaluation of the La Luna on the block.

Drilling operations have concluded at the Pandereta-1 exploration well, with gas encountered in the primary Ciénaga de Oro sandstone reservoir target as anticipated. The well is currently being cased ahead of production testing. The Canadonga-1 well is drilling ahead as planned, and the Corporation anticipates drilling through the primary Ciénaga de Oro sandstone reservoir target next week. The Corporation will provide testing results for both wells when flow testing operations are completed.

The Corporation, through a consortium, participates in an incremental production contract for the Libertador and Atacapi fields in Ecuador whereby the Corporation is 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.

For the three months ended September 30, 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 September 30, 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.

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 September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Production (boepd)						
Esperanza (gas)	**11,244**	7,782	44%	**10,038**	7,143	41%
VIM-5 (gas)	**2,080**	6,958	(70%)	**3,457**	4,054	(15%)
LLA-23 (oil)	**1,035**	1,569	(34%)	**1,195**	1,774	(33%)
Ecuador (tariff oil)	**1,373**	1,711	(20%)	**1,481**	1,728	(14%)
Other (oil)	**855**	612	40%	**742**	643	15%
Total production	**16,587**	18,632	(11%)	**16,913**	15,342	10%
Inventory movements and other	**(80)**	(210)	(62%)	**(82)**	(95)	(15%)
Total sales	**16,507**	18,422	(10%)	**16,831**	15,247	10%
Sales (boepd)						
Esperanza (gas)	**11,166**	7,669	46%	**9,953**	7,081	41%
VIM-5 (gas)	**2,073**	6,952	(70%)	**3,450**	4,025	(14%)
LLA-23 (oil)	**1,037**	1,505	(31%)	**1,200**	1,765	(32%)
Ecuador (tariff oil)	**1,373**	1,711	(20%)	**1,481**	1,728	(14%)
Other (oil)	**858**	585	47%	**747**	648	15%
Total sales	**16,507**	18,422	(10%)	**16,831**	15,247	10%
Realized Contractual Sales (boepd)						
Esperanza (gas)	**11,166**	7,669	46%	**9,953**	7,081	41%
VIM-5 (gas)	**2,073**	6,952	(70%)	**3,450**	4,025	(14%)
Take-or-pay volumes	**99**	486	(80%)	**445**	480	(7%)
Total natural gas	**13,338**	15,107	(12%)	**13,848**	11,586	20%
Total Colombia oil	**1,895**	2,090	(9%)	**1,947**	2,413	(19%)
Ecuador tariff oil	**1,373**	1,711	(20%)	**1,481**	1,728	(14%)
Total realized contractual sales	**16,606**	18,908	(12%)	**17,276**	15,727	10%

The overall decrease in production volumes in the three months ended September 30, 2017, compared to the same period in 2016, is primarily due to three off-takers having scheduled plant maintenance for a combined downtime of 66 days resulting in lower production of 1,505 boepd (8.6 MMscfpd), of which, approximately 25% is related to production from VIM-5 and the remaining production from Esperanza. The scheduled plant maintenance was an annual event that is not expected to recur until next year. While total natural gas production is determined by firm and interruptible contracts, 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. The decrease in production volumes is also related to production declines at LLA-23 and Ecuador.

The overall increase in the production volumes in the nine months ended September 30, 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.

Petroleum and Natural Gas Revenues

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Esperanza	**$ 29,214**	$ 22,504	30%	**$ 78,958**	$ 61,323	29%
VIM-5	**5,197**	20,825	(75%)	**25,888**	35,835	(28%)
LLA-23	**4,134**	4,918	(16%)	**14,136**	14,510	(3%)
Other	**3,422**	1,907	79%	**8,733**	5,461	60%
Petroleum and natural gas revenues, before royalties	**41,967**	50,154	(16%)	**127,715**	117,129	9%
Royalties	**(4,308)**	(7,147)	(40%)	**(14,498)**	(15,225)	(5%)
Petroleum and natural gas revenues, after royalties	**37,659**	43,007	—	**113,217**	101,904	11%
Take-or-pay natural gas income	**291**	1,385	(79%)	**3,599**	4,114	(13%)
Total petroleum and natural gas revenues, after royalties, as reported	**37,950**	44,392	(15%)	**116,816**	106,018	10%
Ecuador tariff and other revenues (1)	**5,308**	6,459	(18%)	**16,424**	19,223	(15%)
Adjusted petroleum and natural gas revenues, after royalties (1)	**$ 43,258**	$ 50,851	(15%)	**$ 133,240**	$ 125,241	6%

(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 and nine months ended September 30, 2017, the Corporation has realized $0.3 million and $3.6 million of take-or-pay income (as described in (2) above), respectively, which is equivalent to 99 boepd and 445 boepd of gas sales, respectively, without actual delivery of the natural gas.

As at September 30, 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 September 30, 2017, undelivered nominations resulted in a deferred income balance of $3 million ($2.9 million related to gas; $0.1 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 Sales Prices

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Brent ($/bbl)	**$ 51.69**	$ 46.52	11%	**$ 52.05**	$ 40.98	27%
West Texas Intermediate ($/bbl)	**$ 48.55**	$ 45.91	6%	**$ 49.23**	$ 41.35	19%
Natural gas ($/boe)	**$ 28.25**	$ 32.21	(12%)	**$ 28.65**	$ 31.93	(10%)
Crude oil ($/boe)	**$ 43.34**	$ 35.50	22%	**$ 43.02**	$ 30.21	42%
Ecuador tariff ($/boe)	**$ 38.54**	$ 38.54	—	**$ 38.54**	$ 38.54	—
Esperanza ($/boe)	**$ 28.44**	$ 31.90	(11%)	**$ 29.06**	$ 31.60	(8%)
VIM-5 ($/boe)	**27.25**	32.56	(16%)	**27.49**	32.49	(15%)
LLA-23 ($/bbl)	**43.33**	35.52	22%	**43.15**	30.01	44%
Ecuador ($/bbl)	**38.54**	38.54	—	**38.54**	38.54	—
Other ($/bbl)	**43.35**	35.43	22%	**42.82**	30.77	39%
Average realized sales price ($/boe) (1)	**$ 30.84**	$ 33.17	(7%)	**$ 31.18**	$ 32.40	(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 sales prices in the three and nine months ended September 30, 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 and nine months ended September 30, 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 seasonal conditions along Colombia’s Caribbean coast negatively impacting the price relating to a small interruptible contract, which has been replaced by a long-term, higher fixed price take-or-pay contract beginning in December 2017. The Guajira price is the local natural gas reference price in Colombia and is set to be redetermined on an annual basis.

Royalties

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	**2017**	2016
Esperanza	**$ 2,542**	$ 1,954	**$ 6,897**	$ 5,429
VIM-5	**1,018**	4,479	**5,316**	7,745
LLA-23	**457**	557	**1,559**	1,615
Other	**291**	157	**726**	436
Total royalties	**$ 4,308**	$ 7,147	**$ 14,498**	$ 15,225

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 LLA-23 and VMM-2 are calculated from crude oil revenue net of transportation expenses. 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%.

Production and Transportation Expenses

Total production and transportation expenses were as follows:

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Production expenses	**$ 5,568**	$ 4,593	21%	**$ 17,360**	$ 12,336	41%
Transportation expenses	**1,988**	691	188%	**2,932**	2,205	33%
Total production and transportation expenses	**$ 7,556**	$ 5,284	43%	**$ 20,292**	$ 14,541	40%
$/boe	**$ 4.98**	$ 3.12	60%	**$ 4.42**	$ 3.48	27%

An analysis of production expenses is provided below:

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Esperanza	**$ 1,763**	$ 1,061	66%	**$ 4,780**	$ 2,621	82%
VIM-5	**694**	583	19%	**2,487**	1,047	138%
LLA-23	**1,808**	1,947	(7%)	**5,452**	5,843	(7%)
Other	**1,303**	1,002	30%	**4,641**	2,825	64%
Total production expenses	**$ 5,568**	$ 4,593	21%	**17,360**	12,336	41%
$/boe						
Esperanza	**$ 1.72**	$ 1.50	15%	**$ 1.76**	$ 1.35	30%
VIM-5	**$ 3.64**	$ 0.91	300%	**$ 2.64**	$ 0.95	178%
Total natural gas	**$ 2.02**	$ 1.22	66%	**$ 1.99**	$ 1.21	64%
LLA-23	**$ 18.95**	$ 14.06	35%	**$ 16.64**	$ 12.08	38%
Total	**$ 3.67**	$ 2.71	35%	**$ 3.78**	$ 2.95	28%

Total natural gas production expenses per boe increased by 66% and 64% to $2.02/boe ($0.35/Mcf) and $1.99/boe ($0.35/Mcf) for the three and nine months ended September 30, 2017, compared to $1.22/boe ($0.21/Mcf) and $1.21/boe ($0.21/Mcf) for the same periods in 2016, respectively. The increase is mainly attributable to 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.

Production expenses at LLA-23 decreased 7% in the three and nine months ended September 30, 2017 compared to the same periods in 2016. The decrease is primarily due to lower production. Despite a 7% decrease in LLA-23 production expenses year over year, the production expenses on a per barrel basis have increased 35% and 38% to $18.95/bbl and $16.64/bbl for the three and nine months ended September 30, 2017, compared to $14.06/boe and $12.08/boe for the same periods in 2016, respectively, due to fixed costs over lower production.

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 September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Esperanza	**$ 813**	$ —	n/a	**$ 813**	$ —	n/a
VIM-5	**1,012**	—	n/a	**1,012**	—	n/a
LLA-23	**44**	507	(91%)	**585**	1,560	(63%)
Other	**119**	184	(35%)	**522**	645	(19%)
Total transportation expenses	**$ 1,988**	$ 691	188%	**$ 2,932**	$ 2,205	33%
$/boe						
Esperanza	**$ 0.79**	$ —	n/a	**$ 0.30**	$ —	n/a
VIM-5	**$ 5.31**	$ —	n/a	**$ 1.07**	$ —	n/a
Total natural gas	**$ 1.50**	$ —	n/a	**$ 0.50**	$ —	n/a
LLA-23	**$ 0.46**	$ 3.66	(87%)	**$ 1.79**	$ 3.23	(45%)
Total	**$ 1.31**	$ 0.41	220%	**$ 0.64**	$ 0.53	21%

In July 2017, the Corporation entered into two temporary gas sales contracts. The temporary gas sales contracts have an integrated sales price whereby the Corporation is responsible for delivering the natural gas to the off-taker at Cartagena. As a result of the temporary gas sales contracts, total natural gas transportation expense of $1.8 million was recorded during the three months ended September 30, 2017. These temporary gas sales contracts had combined production of 1,584 boepd (9 MMscfpd) during the three months ended September 30, 2017.

Transportation expenses at LLA-23 decreased 91% and 63% in the three and nine months ended September 30, 2017, compared to the same periods in 2016, due to a 34% and 33% 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 September 30,			Nine months ended September 30,		
$/boe	**2017**	2016	Change	**2017**	2016	Change
Corporate						
Petroleum and natural gas revenues	**$ 30.84**	$ 33.17	(7%)	**$ 31.18**	$ 32.40	(4%)
Royalties	**(2.84)**	(4.22)	(33%)	**(3.16)**	(3.64)	(13%)
Production expense	**(3.67)**	(2.71)	35%	**(3.78)**	(2.95)	28%
Transportation expense	**(1.31)**	(0.41)	220%	**(0.64)**	(0.53)	21%
Operating netback (1)	**$ 23.02**	$ 25.83	(11%)	**$ 23.60**	$ 25.28	(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

$/boe	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Esperanza						
Natural gas revenues	**$ 28.44**	$ 31.90	(11%)	**$ 29.06**	$ 31.60	(8%)
Royalties	**(2.47)**	(2.77)	(11%)	**(2.54)**	(2.80)	(9%)
Production expense	**(1.72)**	(1.50)	15%	**(1.76)**	(1.35)	30%
Transportation expense	**(0.79)**	—	n/a	**(0.30)**	—	n/a
Operating netback	**$ 23.46**	$ 27.63	(15%)	**$ 24.46**	$ 27.45	(11%)
VIM-5						
Natural gas revenues	**$ 27.25**	$ 32.56	(16%)	**$ 27.49**	$ 32.49	(15%)
Royalties	**(5.34)**	(7.00)	(24%)	**(5.64)**	(7.02)	(20%)
Production expense	**(3.64)**	(0.91)	300%	**(2.64)**	(0.95)	178%
Transportation expense	**(5.31)**	—	n/a	**(1.07)**	—	n/a
Operating netback	**$ 12.96**	$ 24.65	(47%)	**$ 18.14**	$ 24.52	(26%)
Total Natural Gas						
Natural gas revenues	**$ 28.25**	$ 32.21	(12%)	**$ 28.65**	$ 31.93	(10%)
Royalties	**(2.92)**	(4.78)	(39%)	**(3.34)**	(4.33)	(23%)
Production expense	**(2.02)**	(1.22)	66%	**(1.99)**	(1.21)	64%
Transportation expense	**(1.50)**	—	n/a	**(0.50)**	—	n/a
Operating netback	**$ 21.81**	$ 26.21	(17%)	**$ 22.82**	$ 26.39	(13%)

Crude Oil

$/boe	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
LLA-23						
Crude oil revenues	**$ 43.33**	$ 35.52	22%	**$ 43.15**	$ 30.01	44%
Royalties	**(4.79)**	(4.02)	19%	**(4.76)**	(3.34)	43%
Production expense	**(18.95)**	(14.06)	35%	**(16.64)**	(12.08)	38%
Transportation expense	**(0.46)**	(3.66)	(87%)	**(1.79)**	(3.23)	(45%)
Operating netback	**$ 19.13**	$ 13.78	39%	**$ 19.96**	$ 11.36	76%
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 September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Gross costs	**$ 5,772**	$ 5,497	5%	**$ 20,138**	$ 15,025	34%
Less: capitalized amounts	**(889)**	(729)	22%	**(2,632)**	(2,292)	15%
General and administrative expenses	**$ 4,883**	$ 4,768	2%	**$ 17,506**	$ 12,733	37%
$/boe	**$ 3.22**	$ 2.81	15%	**$ 3.81**	$ 3.05	25%

Gross general and administrative expenses ("G&A") increased by 5% and 34% in the three and nine months ended September 30, 2017, compared to same periods in 2016, respectively, primarily due to increased staffing costs in preparation for significantly increased gas production for the remainder of the year and internal reorganization costs during the periods.

Net Finance Income and Expense

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Net financing expense paid	**$ 6,025**	$ 4,434	36%	**$ 17,064**	$ 12,774	34%
Non-cash financing costs	**1,382**	1,277	8%	**8,070**	3,997	102%
Net finance expense	**$ 7,407**	$ 5,711	30%	**$ 25,134**	$ 16,771	50%

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 allows 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 nine months ended September 30, 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.

Hedging Contract

During the nine months ended September 30, 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 September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Hedging contract - unrealized	**$ 151**	$ (47)	n/a	**$ 151**	$ 3	>999%
Hedging contract - realized	**99**	—	n/a	**99**	—	n/a

Stock-Based Compensation Expense and Restricted Share Units

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Stock-based compensation expense	**$ 2,321**	$ 3,569	(35%)	**$ 6,711**	$ 5,456	23%
Restricted share unit expense	**67**	106	—	**3,913**	3,127	25%
Stock-based compensation and restricted share unit expense	**$ 2,388**	$ 3,675	(35%)	**$ 10,624**	$ 8,583	24%

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 September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Depletion and depreciation expense	**$ 10,380**	$ 10,814	(4%)	**$ 25,716**	$ 20,319	27%
$/boe	**$ 6.84**	$ 6.38	7%	**$ 5.60**	$ 4.86	15%

Depletion and deprecation expense decreased 4% in the three months ended September 30, 2017, compared to the same period in 2016, primarily due to lower production.

Depletion and deprecation expense increased 27% in the nine months ended September 30, 2017, compared to the same period in 2016, primarily as a result of a higher depletable base.

Income Tax Expense

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	**2017**	2016
Current income tax expense	**$ 6,826**	$ 8,174	**$ 19,969**	$ 22,335
Deferred income tax expense (recovery)	**(8,485)**	(571)	**(6,572)**	(7,815)
Income tax expense (recovery)	**$ (1,659)**	$ 7,603	**$ 13,397**	$ 14,520

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 40%.

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

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	Change	**2017**	2016	Change
Cash flow provided by operating activities	**$ 11,783**	$ 22,275	(47%)	**$ 40,345**	$ 43,288	(7%)
Per share – basic	**$ 0.07**	$ 0.13	(46%)	**$ 0.23**	$ 0.27	(15%)
Per share – diluted	**$ 0.07**	$ 0.13	(46%)	**$ 0.23**	$ 0.26	(12%)
Adjusted funds from operations (1)	**$ 18,871**	$ 30,719	(39%)	**$ 63,947**	$ 71,040	(10%)
Per share – basic	**$ 0.11**	$ 0.18	(39%)	**$ 0.37**	$ 0.44	(16%)
Per share – diluted	**$ 0.11**	$ 0.18	(39%)	**$ 0.36**	$ 0.43	(16%)
Net income (loss) and comprehensive income (loss)	**$ (1,514)**	$ (8,399)	(82%)	**$ 2,314**	$ 3,307	(30%)
Per share – basic	**$ (0.01)**	$ (0.05)	(80%)	**$ 0.01**	$ 0.02	(50%)
Per share – diluted	**$ (0.01)**	$ (0.05)	(80%)	**$ 0.01**	$ 0.02	(50%)

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

Capital Expenditures

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	**2017**	2016
Drilling and completions	**$ 1,135**	$ 10,016	**$ 25,061**	$ 19,311
Facilities, work overs and infrastructure	**3,379**	3,892	**9,504**	11,503
Midstream pipeline costs	**15,290**	—	**24,607**	—
Land, seismic, communities and other	**5,237**	6,135	**22,152**	13,312
Non-cash costs and adjustments(2)	**(63)**	837	**(1,774)**	(6,317)
Property acquisition	**—**	7,818	**—**	11,483
Net capital expenditures	**24,978**	28,698	**79,550**	49,292
Ecuador	**590**	510	**1,484**	1,241
Adjusted net capital expenditures (1)	**$ 25,568**	$ 29,208	**$ 81,034**	$ 50,533
Net capital expenditures recorded as:				
Expenditures on exploration and evaluation assets	**$ 4,774**	$ 12,465	**$ 37,581**	$ 24,448
Expenditures on property, plant and equipment	**20,204**	8,415	**41,969**	13,361
Property acquisition	**—**	7,818	**—**	11,483
Net capital expenditures	**$ 24,978**	$ 28,698	**$ 79,550**	$ 49,292

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.
(2) Other non-cash costs include capitalized costs related to decommissioning liabilities.

Capital expenditures in the three months ended September 30, 2017 primarily related to:

- Midstream pipeline costs;
- Workover of Pico Plata in VMM-3;
- Facilities costs at Esperanza and VIM-5;
- Seismic costs at VIM-21 and VMM-3;
- Facilities costs related to the Ecuador IPC (accounted for under the equity method of accounting); and
- Other capitalized costs (capitalized G&A of $0.9 million).

As previously announced, the $41 million midstream pipeline project ("Sabanas gas flowline") will be financed through a $30.5 million investment from a group of private investors and a $10.5 million contribution from Canacol (collectively, the "Owners"). The Corporation has incurred $24.6 million to date, and has recorded such contributions as a capital expenditures during the nine months ended September 30, 2017. The Corporation is expected to recover the portion of costs incurred over and above its $10.5 million contribution limit from the private investors by the end of 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 and working capital, defined as current assets less current liabilities, excluding non-cash items. 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, 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.

On February 14, 2017, the Corporation executed a new credit agreement to refinance its BNP Senior Secured Term Loan and Senior Notes, totaling $255 million, into the 2017 Senior Secured Term Loan of $265 million, with the following benefits:

a) a lower the average interest rate, and b) extend the first amortization payment of the new term loan into 2019. In addition, during the nine months ended September 30, 2017, the Corporation sold 7.6 million of the 16.2 million investment in shares of Interoil Exploration and Production ASA ("Interoil") for proceeds of $4.1 million.

		September 30, 2017
Bank debt – principal	$	305,000
Working capital surplus		(62,168)
Net debt	$	242,832

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 $11.1 million of transaction costs netted against the principal amounts as at September 30, 2017. The 2017 Senior Secured Term Loan agreement also allows 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 nine months ended September 30, 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. The purpose of including this last amount is to capture the funds from operations of the Corporation's joint venture in Ecuador into the calculation as it is accounted for on an equity consolidation basis in the Corporation's financial statements.

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		September 30, 2017
Bank debt – principal	$	305,000
Finance lease obligation		29,708
Debt service reserve account balance		(5,320)
Consolidated Total Debt	$	329,388

Consolidated EBITDAX	Q4	Q1	Q2	Q3	Rolling
Consolidated net income (loss)	20,339	(7,942)	11,770	(1,514)	22,653
(+) Interest expense	5,274	6,405	6,221	6,743	24,643
(+/-) Income taxes (recovery)	(48,603)	3,777	11,279	(1,659)	(35,206)
(+) Wealth taxes	—	450	24	(16)	458
(+) Depletion and depreciation	6,193	9,797	5,539	10,380	31,909
(+) Pre-license and exploration expenses	2,808	23	23	1,069	3,923
(-) Equity (loss) profit	1,779	(286)	(493)	(268)	732
(+/-) Other non-cash expenses (income)	42,433	16,628	(11,016)	12,869	60,914
(+) Contribution of Ecuador IPC	5,976	5,392	5,724	5,308	22,400
Consolidated EBITDAX	36,199	34,244	29,071	32,912	132,426
(+/-) Ecuador IPC receivable adjustment	(2,751)	(5,392)	13,751	(5,308)	300
Covenant EBITDAX	33,448	28,852	42,822	27,604	132,726

Consolidated Leverage Ratio		September 30, 2017
Consolidated Total Debt	$	329,388
Consolidated EBITDAX		132,726
Consolidated Leverage Ratio		2.48

The Consolidated Interest Coverage Ratio is calculated as follows:

Consolidated Interest Coverage Ratio		September 30, 2017
Consolidated Interest Expense	$	24,643
Consolidated EBITDAX		132,726
Consolidated Interest Coverage Ratio		5.39

The Corporation was in compliance with its covenants as at September 30, 2017.

Other Colombian Credit Facilities

The Corporation has revolving lines of credit in place in Colombia with an aggregate borrowing base of $52.4 million (COP 153.9 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. The facilities were undrawn as at September 30, 2017.

Letters of Credit

At September 30, 2017, the Corporation had letters of credit outstanding totaling $80 million to guarantee work commitments on exploration blocks in Colombia and to guarantee other contractual commitments. The total of these letters of credit, net of amounts counter-guaranteed by other financial institutions, reduce the amounts available under the Colombian revolving lines of credit by $52.4 million to $nil at September 30, 2017.

At November 13, 2017, the Corporation had 175.9 million common shares, 15.1 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 September 30, 2017:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	$ —	$ 164,231	$ 140,769	$ 305,000
Jobo facility finance lease obligation – undiscounted	8,618	18,714	11,841	39,173
Trade and other payables	14,471	—	—	14,471
Crude oil payable in kind	622	—	—	622
Hedging contract	151	—	—	151
Taxes payable	2,412	—	—	2,412
Deferred income	2,966	3,731	—	6,697
Other long term obligations	—	—	2,769	2,769
Restricted share units	2,116	34	—	2,150
Exploration and production contracts	25,894	52,628	7,132	85,654
Jobo facility operating contract	3,390	7,275	5,601	16,266
Compression station lease contract (1)	2,161	10,635	44,200	56,996
Liquid natural gas processing contract	2,356	5,654	8,300	16,310
Office leases	1,081	1,446	1,325	3,852

(1) The Corporation entered into a lease contract during the three months ended September 30, 2017, for the compression of natural gas for its Sabanas pipeline, subject to lenders' approval, allowing for an amendment to the existing Senior Secured Term Loan Agreement. A portion of the compression lease contract is expected to be recorded as a finance lease upon commencement of operations.

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 September 30, 2017 of $85.7 million and has issued $31.3 million in financial guarantees related thereto. These commitments are planned to be satisfied by means of seismic work, exploration drilling and farm-outs.

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 September 30, 2017 are $7.56 / barrel and $2.97 / barrel, respectively. The ship-or-pay contracts will expire in November 2025 and 2028, respectively.

Ecuador Incremental Production Contract

In addition to the contractual obligations described above, the Corporation has a non-operated 25% equity participation interest in a joint-venture consortium which in 2012 was awarded an incremental production contract for the Libertador and Atacapi mature oil fields in Ecuador. The consortium plans to incur capital expenditures estimated for a total of $397 million ($107.6 million net to the Corporation) over the 15 year term of the contract. As at September 30, 2017, the Corporation had incurred a net $86.8 million of capital expenditures in connection with its Ecuador IPC commitment and has a remaining commitment of $20.8 million. It is anticipated that cash flows from the Ecuador IPC is sufficient to sustain envisioned future capital development.

OUTLOOK

Drilling operations have concluded at the Pandereta-1 exploration well, with gas encountered in the primary Ciénaga de Oro sandstone reservoir target as anticipated. The well is currently being cased ahead of production testing. The Canadonga-1 well is drilling ahead as planned, and the Corporation anticipates drilling through the primary Ciénaga de Oro sandstone reservoir target later this week. The Corporation will provide testing results for both wells when flow testing operations are completed.

The Sabanas gas flowline project remains on schedule and is expected to be completed by December 1, 2017. Once completed, the flowline will add 40 MMscfpd of pipeline capacity to the Corporation, to allow for a total of 130 MMscfpd of gas sales. The Sabanas flowline will have an initial transportation capacity of 20 MMscfpd on December 1, 2017, and a final transportation capacity of 40 MMscfpd in mid-January, 2018, once final compression has been installed and tested. The productive capacity of the Corporation's current gas wells is approximately 195 MMscfpd, and that of the Corporation's gas processing facilities located at Jobo approximately 200 MMscfpd.

SUMMARY OF QUARTERLY RESULTS

	2017			2016				2015
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial								
Total Petroleum and natural gas revenues, net of royalties	**37,950**	37,283	41,583	41,967	44,392	38,926	22,700	17,402
Adjusted petroleum and natural gas revenues, net of royalties (1)	**43,258**	43,007	46,975	47,943	50,851	45,390	29,000	24,883
Cash flow provided by operating activities	**11,783**	11,130	17,539	30,289	22,275	13,764	7,249	4,974
Per share – basic ($)	**0.07**	0.06	0.10	0.17	0.13	0.09	0.05	0.03
Per share – diluted ($)	**0.07**	0.06	0.10	0.17	0.13	0.08	0.05	0.03
Adjusted funds from operations (1)	**18,871**	24,236	20,947	41,979	30,719	26,870	13,451	8,473
Per share – basic ($) (1)	**0.11**	0.14	0.12	0.24	0.18	0.17	0.08	0.05
Per share – diluted ($) (1)	**0.11**	0.14	0.12	0.24	0.18	0.16	0.08	0.05
Net income (loss) and comprehensive income (loss)	**(1,514)**	11,770	(7,942)	20,331	(8,399)	11,245	461	(84,466)
Per share – basic ($)	**(0.01)**	0.07	(0.05)	0.12	(0.05)	0.07	—	(0.54)
Per share – diluted ($)	**(0.01)**	0.07	(0.05)	0.12	(0.05)	0.07	—	(0.54)
Capital expenditures, net	**24,978**	30,572	24,000	58,638	28,698	5,046	15,548	22,394
Adjusted capital expenditures, net (1)	**25,568**	30,648	24,818	59,691	29,208	5,376	15,949	22,867
Operations (boepd)								
Petroleum and natural gas production, before royalties								
Petroleum (2)	**3,263**	3,487	3,505	3,616	3,892	4,018	4,526	5,523
Natural gas	**13,324**	13,675	13,487	14,112	14,740	12,405	6,407	3,541
Total (2)	**16,587**	17,162	16,992	17,728	18,632	16,423	10,933	9,064
Petroleum and natural gas sales, before royalties								
Petroleum (2)	**3,268**	3,500	3,517	3,657	3,801	4,045	4,578	5,468
Natural gas	**13,239**	13,563	13,409	13,986	14,621	12,331	6,329	3,542
Total (2)	**16,507**	17,063	16,926	17,643	18,422	16,376	10,907	9,010
Realized contractual sales, before royalties								
Natural gas	**13,338**	13,695	14,526	14,653	15,107	12,972	6,642	3,891
Colombia oil	**1,895**	1,933	2,014	2,026	2,090	2,294	2,856	3,390
Ecuador tariff oil (2)	**1,373**	1,567	1,503	1,631	1,711	1,751	1,722	2,078
Total (2)	**16,606**	17,195	18,043	18,310	18,908	17,017	11,220	9,359

(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

There have been no significant changes in the three months ended September 30, 2017 to the risks and uncertainties as identified in the MD&A for the year ended December 31, 2016.

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 unaudited interim condensed consolidated financial statements of the Corporation as at and for the three and nine months ended September 30, 2017 and the audited consolidated financial statements as at and for the year ended December 31, 2016.

REGULATORY POLICIES

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("DC&P") are designed to provide reasonable assurance that all relevant information is gathered and reported on a timely basis to senior management so that appropriate decisions can be made regarding public disclosure. 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, disclosure controls and procedures and established processes to ensure that they are provided with sufficient knowledge to support the representations made in the interim certificates required to be filed under National Instrument 52-109.

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.

During the three months ended September 30, 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.