CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
YEAR ENDED JUNE 30, 2014

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Petroleum and natural gas revenues, net of royalties	**61,744**	38,961	58%	**207,787**	141,354	47%
Adjusted petroleum and natural gas revenues, net of royalties, including revenues related to the Ecuador IPC (2)	**68,351**	41,796	64%	**227,510**	147,666	54%
Cash provided by (used in) operating activities	**8,715**	21,739	(60%)	**77,944**	26,055	199%
Per share – basic ($)	**0.09**	0.25	(64%)	**0.87**	0.35	149%
Per share – diluted ($)	**0.09**	0.25	(64%)	**0.86**	0.35	146%
Adjusted funds from operations (1) (2) (5)	**23,371**	19,102	22%	**95,522**	51,153	87%
Per share – basic ($)	**0.24**	0.22	9%	**1.06**	0.68	56%
Per share – diluted ($)	**0.23**	0.22	5%	**1.06**	0.68	56%
Net income (loss)	**(2,070)**	(119,046)	(98%)	**9,937**	(127,807)	n/a
Per share – basic ($)	**(0.02)**	(1.38)	(99%)	**0.11**	(1.71)	n/a
Per share – diluted ($)	**(0.02)**	(1.38)	(99%)	**0.11**	(1.71)	n/a
Capital expenditures, net (4)	**77,093**	13,096	489%	**153,165**	50,540	203%
Adjusted capital expenditures, net, including capital expenditures related to the Ecuador IPC (1)(2) (4)	**87,584**	15,755	456%	**188,109**	67,808	177%
				June 30, 2014	June 30, 2013	Change
Cash and cash equivalents				**163,729**	52,290	213%
Restricted cash				**66,827**	26,394	153%
Working capital surplus, excluding the current portion of bank debt and non-cash items (1)				**159,117**	69,148	130%
Short-term and long-term bank debt				**210,688**	134,316	57%
Total assets				**756,587**	469,592	61%
Common shares, end of period (000s)				**107,736**	86,506	25%

Operating	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Petroleum and natural gas **production**, before royalties (boepd)						
Petroleum (3)	**9,271**	5,390	72%	**7,652**	5,310	44%
Natural gas	**2,941**	2,879	2%	**2,925**	1,507	94%
Total (2)	**12,212**	8,269	48%	**10,577**	6,817	55%
Petroleum and natural gas **sales**, before royalties (boepd)						
Petroleum (3)	**9,386**	5,372	75%	**7,577**	5,452	39%
Natural gas	**2,937**	2,914	1%	**2,893**	1,516	91%
Total (2)	**12,323**	8,286	49%	**10,470**	6,968	50%
Realized sales prices ($/boe)						
LLA-23 (oil)	**92.39**	86.03	7%	**90.29**	91.12	(1%)
Esperanza (natural gas)	**23.21**	29.47	(21%)	**26.49**	30.05	(12%)
Rancho Hermoso (tariff and non-tariff oil and liquids)	**92.23**	84.19	10%	**90.41**	72.39	25%
Ecuador (tariff oil) (2)	**38.54**	38.54	-	**38.54**	38.54	-
Total (2)	**66.92**	60.39	11%	**65.10**	62.99	3%
Operating netbacks ($/boe) (1)						
LLA-23 (oil)	**67.37**	58.54	15%	**65.30**	61.40	6%
Esperanza (natural gas)	**18.32**	24.49	(25%)	**21.95**	25.22	(13%)
Rancho Hermoso (tariff and non-tariff oil and liquids)	**13.96**	23.17	(40%)	**19.51**	24.47	(20%)
Ecuador (tariff oil) (2)	**38.54**	38.54	-	**38.54**	38.54	-
Total (2)	**44.70**	32.14	39%	**41.85**	28.32	48%

(1) Non-IFRS measure – 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.
(4) Excludes business acquisition.
(5) Included in adjusted funds from operations for the three months ended June 30, 2014 were cash outflows totalling $10.6 million related to the final payment under the May 2013 RSU grant and other non-recurring settlements. Without such outflows, adjusted funds from operations were $34.0 million on a pro forma basis.

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, with non-core activities in Brazil and Peru. 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 under the symbol CNE, the OTCQX in the United States of America under the symbol CNNEF, and the Bolsa de Valores de Colombia under the symbol CNEC.

Advisories

The following management's discussion and analysis ("MD&A") is dated September 22, 2014 and is the Corporation's explanation of its financial performance for the year 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 years ended June 30, 2014 and 2013 (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, 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.

Change in Accounting Policy – IFRS 11 "Joint Arrangements", which became effective for the Corporation on July 1, 2013, divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting.

Upon the adoption of IFRS 11, the Corporation reviewed and assessed the legal form and terms of the contractual arrangements in relation to the Corporation's investments in joint arrangements. The adoption of IFRS 11 resulted in a change in the method of accounting for the Corporation's interest in the incremental production contract for the Libertador and Atacapi fields in Ecuador (the "Ecuador IPC") from a jointly-controlled entity, using the proportionate consolidation method, to being accounted for using the equity method. This change in accounting for the Corporation's investment in the Ecuador IPC has been applied in accordance with the relevant IFRS transitional provisions. The initial investment in the Ecuador IPC as at July 1, 2012 for the purposes of applying the equity method was measured as the aggregate of the carrying amounts of the assets and liabilities that the Corporation had previously proportionately consolidated. The change in accounting method has affected the amounts previously reported in the Corporation's financial statements.

As further described in the next section, the Corporation has provided supplemental disclosures related to revenues, expenditures and funds flows from the Ecuador IPC.

Non-IFRS Measures – *Due to the nature of the equity method of accounting the Corporation applies under IFRS 11 to its interest in the 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 flows 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 earnings per share. The following table reconciles the Corporation's cash provided by operating activities to adjusted funds from operations:

	Three months ended June 30,		Year ended June 30,	
	2014	2013	**2014**	2013
Cash provided by operating activities	**$ 8,715**	$ 21,739	**$ 77,944**	$ 26,055
Changes in non-cash working capital	**8,049**	(5,472)	**(2,145)**	18,786
Ecuador IPC revenue, net of current income tax	**6,607**	2,835	**19,723**	6,312
Adjusted funds from operations (1)	**$ 23,371**	$ 19,102	**$ 95,522**	$ 51,153

(1) Included in adjusted funds from operations for the three months ended June 30, 2014 were cash outflows totalling $10.6 million related to the final payment under the May 2013 RSU grant and other non-recurring settlements. Without such outflows, adjusted funds from operations were $34.0 million on a pro forma basis.

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, excluding non-cash items such as the current portion of commodity contracts, the current portion of convertible debentures, the current portion of warrants, and the current portion of any embedded derivatives asset/liability, 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 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

Producing Field Overview

For the three months ended June 30, 2014, the Corporation's production primarily consisted of crude oil and natural gas liquids from its Leono, Labrador, Pantro and Rancho Hermoso fields in the Llanos Basin in Colombia, natural gas from its Esperanza block in the Lower Magdalena Basin in Colombia, crude oil from the Ecuador IPC, and, to a lesser extent, crude oil from its Capella, VMM-2 and Santa Isabel properties in Colombia.

Over the past two years the Corporation has made four key light oil discoveries on its LLA-23 block located in the Llanos basin. These discoveries are currently producing approximately half of the Corporation's current production and the Corporation is focused on developing the existing discoveries to their full productive potential, at the same time continuing the exploration drilling of the remaining portfolio throughout the remainder of calendar 2014 and throughout 2015 and 2016. The first discovery, Labrador, was made in December 2012, and the Corporation has drilled and completed its fourth development well, Labrador-4, into the field in June 2014. The Leono discovery was made in December 2013, and the Corporation has drilled and completed the third well, Leono-3, into the field in May 2014. The third discovery, Pantro, was made in April 2014, with two reservoirs, the Gacheta and the Mirador, testing 2,930 and 1,038 bopd of gross light oil respectively from the Pantro-1 well. The Corporation has drilled its second well, Pantro-2, into the field in August 2014. The Pantro-2 well encountered oil pay within the C7, Gacheta, and Ubaque sandstone reservoirs and tested 848 bopd gross of 35° API oil in the C7 sandstone reservoir. The Corporation plans to leave the Pantro-2 appraisal well on long term production test from the C7 sandstone reservoir subject to approval by the Agencia Nacional de Hidrocarburos ("ANH"). Finally, the Tigro-1 exploration well tested 1,206 bopd gross (1,085 bopd net) of 35° API oil with 2% water cut during a six day flow period in the Mirador sandstone reservoir. The Corporation plans to leave the Tigro-1 exploration well on long term production test from the Mirador sandstone reservoir subject to approval by the ANH. The Corporation is currently skidding the rig in preparation of drilling the Tigro-3 well, which is located approximately one kilometer to the south of the Tigro-1 discovery well. Upon completion of the drilling and testing of the Tigro-3 well, the Corporation plans to drill the Tigro-2 well, subject to the approval of the ANH.

Based on its exploration successes on the LLA-23 block, the Corporation has recently added a second drilling rig to its program in order to accelerate the drilling of additional exploration wells, including the remaining two exploration wells at Maltes-1 and Pastor-1, and up to three development wells throughout the remainder of calendar 2014 and into early 2015. The Corporation also commenced the acquisition of a 400 square kilometer 3D seismic program in August 2014. The objective of the 3D seismic program is to firm up the portfolio of 12 currently identified exploration leads into prospects for drilling in calendar 2015 and 2016.

The Esperanza block, located in the Lower Magdalena Basin in Colombia, produces dry natural gas for sale to local customers under long-term contracts. During the quarter ended June 30, 2014, the Corporation completed the drilling of the first well of its three well gas exploration program, Palmer-1, which tested 15.5 million standard cubic feet per day ("MMcfpd") (2,730 barrels of oil equivalent "boepd") of dry gas. As disclosed in January and September 2014, the Corporation has executed three new gas sales contracts for a combined 65 MMcfpd which will take Canacol's current daily gas production of approximately 18 MMcfpd (3,170 boepd) to 83 MMcfpd (14,912 boepd) in late calendar 2015. The new contracts each have a five year term, with pricing of $ 5.40/million British thermal units ("MMbtu") escalated at 2% per year for two of the contracts totalling 35 MMcfpd, and $8.00/MMbtu escalated at approximately 3% per year for the third contract of 30 MMcfpd. Canacol currently sells approximately 18 MMcfpd (3,170 barrels of oil equivalent per day) of gas from the Nelson Field to a local ferronickel producer under a 10 year contract that expires in 2021. Upon the completion of testing operations at Palmer-1, the Corporation plans to spud the second of three planned exploration wells on the Esperanza contract targeting the Cienaga de Oro reservoir, Corozo 1, in early October 2014 subject to approval by the ANH. The Corporation plans to commence drilling of the third exploration well, Canandonga-1, in December 2014, subject to approval by the ANH.

The Corporation, through a consortium, participates in an incremental production contract for the Libertador and Atacapi fields in Ecuador whereby the Corporation receives 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, the Corporation changed its accounting policy with respect to the Ecuador IPC as required under IFRS 11, which became effective to the Corporation on July 1, 2013. This resulted in the Ecuador IPC being accounted for under the equity method of accounting versus the proportionate consolidation method of accounting, which was previously applied. 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.

Ecuador tariff production has steadily increased since the year ended June 30, 2013 and is expected to continue to increase into calendar 2016, when it is expected to reach peak production. During the quarter ended June 30, 2014, the Corporation participated in the drilling of three new development wells and the work over of two existing wells to add new production. The consortium plans to drill five additional new development wells and work over three existing producing wells in the remainder of calendar 2014.

Crude oil production from Rancho Hermoso falls under either: i) "non-tariff", which represents crude oil produced under a production sharing contract with Ecopetrol S.A. ("Ecopetrol"), the state oil company of Colombia; or ii) "tariff" production, which represents crude oil produced under a risk service contract with Ecopetrol whereby the Corporation receives a set tariff price per barrel of oil produced. Tariff production is limited to one specific formation, the Mirador formation, while non-tariff production is derived from the remaining formations, including the Ubaque, Guadalupe, Barco Los Cuervos, Carbonera and Gacheta. Natural gas liquids production includes naphtha from the processing of associated gas from the Rancho Hermoso field. Under its contracts with Ecopetrol, the Corporation is responsible for 100% of the production expenses of the field, while it recognizes 100% of gross tariff production and only 24-25% of gross non-tariff production before royalties. Consequently, average production expenses per barrel are higher due to this additional cost burden under the non-tariff production sharing contract. Similarly, the price received for tariff oil (currently established at $17.36/bbl to the end of the contract) is significantly below benchmark oil prices and, therefore, reduces average sales prices in the field, depending on the level of tariff oil production. Rancho Hermoso is a mature field and the Corporation plans to undertake limited additional work over activities with the objective to maintain profitable operations and maximize free cash flows until it reaches its economic limit.

For the three months ended June 30, 2014, the Corporation also had other crude oil production from its Capella, VMM-2 and Santa Isabel properties in Colombia. At Santa Isabel, during the three months ended June 30, 2014, the Corporation drilled one exploration well (Morsa-1) and one appraisal of its Oso Pardo discovery (Oso Pardo-2) made in calendar 2013. The Morsa-1 exploration well encountered oil pay in two separate sandstone reservoirs within the Umir formation and tested 832 bopd of 25° API oil. The Oso Pardo-2 appraisal well encountered 149 feet of oil pay within the Umir and Lisama sandstone reservoirs and is currently undergoing production testing. On the neighboring VMM-2 block, the Corporation along with its partner are completing the production testing of the Lisama discovery at the MA-2 and MA-5 wells, and continue to test naturally fractured shales and carbonates of the La Luna in its MA-1 discovery well. The Corporation and its partner plan to drill an additional appraisal well into the shallow Lisama discovery prior to the end of 2014. The operator of the Capella property (10% WI) is expected to continue its extensive development program for the field through calendar 2014.

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

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 June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Production (boepd)						
LLA-23 (oil)	**5,774**	1,732	233%	**4,291**	826	419%
Esperanza (gas)	**2,941**	2,879	2%	**2,925**	1,507	94%
Rancho Hermoso (tariff and non-tariff oil and liquids)	**1,011**	2,476	(59%)	**1,548**	3,803	(59%)
Ecuador (tariff oil)	**1,884**	808	133%	**1,402**	449	213%
Other (oil)	**602**	374	61%	**411**	232	77%
Total production	**12,212**	8,269	48%	**10,577**	6,817	55%
Inventory movements, power generation and other	**111**	17	553%	**(107)**	151	n/a
Total sales	**12,323**	8,286	49%	**10,470**	6,968	50%
Sales (boepd)						
LLA-23 (oil)	**5,751**	1,703	238%	**4,348**	745	484%
Esperanza (gas)	**2,937**	2,914	1%	**2,893**	1,516	91%
Rancho Hermoso (tariff and non-tariff oil and liquids)	**1,031**	2,527	(59%)	**1,385**	4,066	(66%)
Ecuador (tariff oil)	**1,884**	808	133%	**1,402**	449	213%
Other (oil)	**720**	334	116%	**442**	192	130%
Total sales	**12,323**	8,286	49%	**10,470**	6,968	50%

The overall increase in production volumes in the three months and year ended June 30, 2014 compared to the same periods in 2013 is primarily due to new production from the Labrador and Leono discoveries on the LLA-23 block and production increases from the Libertador and Atacapi fields in Ecuador.

Petroleum and Natural Gas Revenues

	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
LLA-23	**$ 48,354**	$ 13,332	263%	**$ 143,299**	$ 24,765	479%
Esperanza	**6,204**	7,816	(21%)	**27,973**	16,622	68%
Rancho Hermoso	**8,653**	19,360	(55%)	**45,712**	107,424	(57%)
Other	**5,229**	2,190	139%	**12,090**	5,031	140%
Petroleum and natural gas revenues, before royalties	**68,440**	42,698	60%	**229,074**	153,842	49%
Royalties	**(6,696)**	(3,737)	79%	**(21,287)**	(12,488)	70%
Petroleum and natural gas revenues, after royalties, as reported	**61,744**	38,961	58%	**207,787**	141,354	47%
Ecuador (1)	**6,607**	2,835	133%	**19,723**	6,312	212%
Adjusted petroleum and natural gas revenues, after royalties (1)	**$ 68,351**	$ 41,796	64%	**$ 227,510**	$ 147,666	54%

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

Adjusted petroleum and natural gas revenues include tariff revenues from the Ecuador IPC.

The increase in adjusted petroleum and natural gas revenues in the three months and year ended June 30, 2014 compared to the same periods in 2013 is primarily the result of the increased overall sales of 49% and 50% by volume, respectively, and the impact of higher realized average prices.

Average Benchmark and Realized Sales Prices

	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Brent ($/bbl)	**$ 109.69**	$ 102.56	7%	**$ 109.33**	$ 108.60	1%
West Texas Intermediate ($/bbl)	**$ 103.32**	$ 94.05	10%	**$ 101.35**	$ 92.10	10%
LLA-23 ($/bbl)	**$ 92.39**	$ 86.03	7%	**$ 90.29**	$ 91.12	(1%)
Esperanza ($/boe)	**23.21**	29.47	(21%)	**26.49**	30.05	(12%)
Rancho Hermoso ($/bbl)	**92.23**	84.19	10%	**90.41**	72.39	25%
Ecuador ($/bbl) (1)	**38.54**	38.54	-	**38.54**	38.54	-
Other ($/bbl)	**79.81**	72.05	11%	**75.07**	71.87	4%
Average realized sales price ($/boe) (1)	**$ 66.92**	$ 60.39	11%	**$ 65.10**	$ 62.99	3%

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

In January 2014, the Guajira Index, the natural gas reference price used as a basis for the calculation of the Corporation's current Esperanza sales contracts, was reduced to $3.97/MMbtu ($22.63/boe) by decree of the "Comision de Regulacion de Energia y Gas" ("CREG") of Colombia. The decree was made by the CREG as part of temporary measures involved in bridging the time from January 1, 2014, when certain amendments to the applicable legislation in Colombia came into force, and the establishment of a "market regulator" that will be in charge of calculating and publishing a Guarjira average price as mandated by such legislation. As of June 20, 2014, the market regulator has been established and the Corporation expects a revision of Guajira pricing within the next two to three months to more normalized levels. As described above, the Corporation has moved away from Guajira pricing with its three new gas contracts at Esperanza commencing in December 2015 for 65 MMcfpd (11,404 boepd) for a five year period at a fixed price of $5.40/MMbtu for 35 MMcfpd, under contracts executed in December 2013, and $8.00/MMbtu for 30 MMcfpd under the most recent contract executed in September 2014.

Royalties

	Three months ended June 30,		Year ended June 30,	
	2014	2013	**2014**	2013
LLA-23	**$ 5,140**	$ 1,273	**$ 14,436**	$ 2,335
Esperanza	**474**	659	**2,289**	1,386
Rancho Hermoso	**680**	1,615	**3,708**	8,363
Other	**402**	190	**854**	404
Total royalties	**$ 6,696**	$ 3,737	**$ 21,287**	$ 12,488

In Colombia, crude oil royalties are generally at a rate of 8% until net field production reaches 5,000 boepd, then increase on a sliding scale to 20% up to field production of 125,000 boepd. Crude oil royalties in Rancho Hermoso are taken in kind. The Corporation's LLA-23 and VMM-2 blocks are subject to an additional x-factor royalty of 3% (effectively 2.76%). Crude oil royalties in LLA-23 and VMM-2 are calculated from crude oil revenue net of transportation expenses. The Corporation's Capella heavy oil field is subject to a 6% royalty. There are no royalties on tariff production in Ecuador. Natural gas royalties are calculated from natural gas revenue, generally at a rate of 6.4%. In addition, the Corporation's natural gas production is subject to an additional overriding royalty of 2%.

Production and Transportation Expenses

Total production and transportation expenses were as follows:

	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Production expenses	**$ 14,431**	$ 14,109	2%	**$ 51,233**	$ 62,363	(18%)
Transportation expenses	**3,791**	3,453	10%	**16,326**	13,265	23%
Total production and transportation expenses	**$ 18,222**	$ 17,562	4%	**$ 67,559**	$ 75,628	(11%)
$/boe	**$ 16.25**	$ 23.29	(30%)	**$ 17.68**	$ 29.74	(41%)

An analysis of production expenses is provided below:

	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
LLA-23	**$ 5,357**	$ 1,846	190%	**$ 16,192**	$ 3,076	426%
Esperanza	**834**	661	26%	**2,498**	1,284	95%
Rancho Hermoso	**5,842**	10,416	(44%)	**26,056**	53,175	(51%)
Other	**2,398**	1,186	102%	**6,487**	4,828	34%
Total production expenses	**$ 14,431**	$ 14,109	2%	**$ 51,233**	$ 62,363	(18%)
$/boe						
LLA-23	**$ 10.24**	$ 11.91	(14%)	**$ 10.20**	$ 11.32	(10%)
Esperanza	**$ 3.12**	$ 2.49	25%	**$ 2.37**	$ 2.32	2%
Rancho Hermoso	**$ 62.27**	$ 45.30	37%	**$ 51.53**	$ 35.83	44%
Total	**$ 12.87**	$ 18.71	(31%)	**$ 13.41**	$ 24.53	(45%)

Production expenses at LLA-23 increased 190% and 426% in the three months and year ended June 30, 2014, respectively, compared to the same periods in 2013. The increase is primarily due to new production from the Labrador, Leono and Pantro discoveries.

Production expenses at Esperanza increased 26% in the three months ended June 30, 2014 compared to the same period in 2013, primarily due to one-time generator and equipment maintenance costs totalling $0.2 million incurred during the quarter. The Corporation acquired the Esperanza block in December 2012 and, as a result, such block only had six months of operations during the year ended June 30, 2013. Consequently, production expenses at Esperanza increased 95% in the year ended June 30, 2014 compared to the same period in 2013.

Production expenses at Rancho Hermoso decreased 44% and 51% in the three months and year ended June 30, 2014, respectively, compared to the same periods in 2013. The decrease is the result of decreased production in the field. However, since much of the costs of the field are not directly variable with production volumes, per barrel production expenses have increased by 37% and 44% from the three months and year ended June 30, 2013 to the same periods in 2014, respectively. Under its contract with Ecopetrol, the Corporation pays 100% of the production expenses at Rancho Hermoso while only recognizing non-tariff production before royalties of approximately 24-25% of gross non-tariff production. As a result, production expenses per barrel for Rancho Hermoso oil are higher than a similar operation that is subject to an ANH contract, such as LLA-23, Capella, VMM-2 and Santa Isabel. As Rancho Hermoso is a mature field, the Corporation intends to manage the operation with the objective to maintain profitable operations and maximize free cash flows until it reaches its economic limit.

The Corporation does not pay production expenses in Ecuador.

An analysis of transportation expenses is provided below:

	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
LLA-23	**$ 2,598**	$ 1,140	128%	**$ 9,027**	$ 2,667	239%
Rancho Hermoso	**821**	2,001	(59%)	**6,086**	9,565	(36%)
Other	**372**	312	19%	**1,212**	1,033	17%
Total transportation expenses	**$ 3,791**	$ 3,453	10%	**$ 16,325**	$ 13,265	23%
$/boe						
LLA-23	**$ 4.96**	$ 7.36	(33%)	**$ 5.69**	$ 9.81	(42%)
Rancho Hermoso	**$ 8.75**	$ 8.70	1%	**$ 12.04**	$ 6.45	87%
Total	**$ 3.38**	$ 4.58	(26%)	**$ 4.27**	$ 5.22	(18%)

Total transportation expenses have increased by 10% and 23% in the three months and year ended June 30, 2014, respectively, compared to the same periods in 2013 mainly due to increased sales volumes. The Corporation does not pay transportation costs at Esperanza or in Ecuador.

Operating Netbacks

$/boe	Three months ended June 30, 2014	2013	Change	Year ended June 30, 2014	2013	Change
Petroleum and natural gas revenues	**$ 66.92**	$ 60.39	11%	**$ 65.10**	$ 62.99	3%
Royalties	**(5.97)**	(4.96)	20%	**(5.57)**	(4.92)	13%
Production and transportation expenses	**(16.25)**	(23.29)	(30%)	**(17.68)**	(29.75)	(41%)
Operating netback (1)	**$ 44.70**	$ 32.14	39%	**$ 41.85**	$ 28.32	48%

(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:

$/boe	Three months ended June 30, 2014	2013	Change	Year ended June 30, 2014	2013	Change
LLA-23						
Crude oil revenues	**$ 92.39**	$ 86.03	7%	**$ 90.29**	$ 91.12	(1%)
Royalties	**(9.82)**	(8.22)	20%	**(9.10)**	(8.59)	6%
Production and transportation expenses	**(15.20)**	(19.27)	(21%)	**(15.89)**	(21.13)	(25%)
Operating netback	**$ 67.37**	$ 58.54	15%	**$ 65.30**	$ 61.40	6%
Esperanza						
Natural gas revenues	**$ 23.21**	$ 29.47	(21%)	**$ 26.49**	$ 30.05	(12%)
Royalties	**(1.77)**	(2.49)	(29%)	**(2.17)**	(2.51)	(14%)
Production expenses	**(3.12)**	(2.49)	25%	**(2.37)**	(2.32)	2%
Operating netback	**$ 18.32**	$ 24.49	(25%)	**$ 21.95**	$ 25.22	(13%)
Rancho Hermoso						
Petroleum and tariff revenues	**$ 92.23**	$ 84.19	10%	**$ 90.41**	$ 72.39	25%
Royalties	**(7.25)**	(7.02)	3%	**(7.33)**	(5.64)	30%
Production and transportation expenses	**(71.02)**	(54.00)	32%	**(63.57)**	(42.28)	50%
Operating netback	**$ 13.96**	$ 23.17	(40%)	**$ 19.51**	$ 24.47	(20%)
Ecuador						
Tariff revenues (1)	**$ 38.54**	$ 38.54	-	**$ 38.54**	$ 38.54	-
Operating netback (1)	**$ 38.54**	$ 38.54	-	**$ 38.54**	$ 38.54	-

(1) Revenues related to the Ecuador IPC are not included in Petroleum and Natural Gas Revenues as reported under IFRS – see "Non-IFRS Measures" section above.

Other fields in Colombia contributed only a minor amount to total revenues (<10%) in the three months and year ended June 30, 2014 and 2013 and, therefore, a separate operating netback analysis is not provided.

General and Administrative Expenses

	Three months ended June 30, 2014	2013	Change	Year ended June 30, 2014	2013	Change
Gross costs	**$ 7,962**	$ 6,023	32%	**$ 30,555**	$ 24,115	27%
Less: capitalized amounts / reversal	**(982)**	(464)	112%	**(3,510)**	(1,879)	87%
General and administrative expenses	**$ 6,980**	$ 5,559	26%	**$ 27,045**	$ 22,236	22%
$/boe	**$ 6.22**	$ 7.37	(16%)	**$ 7.08**	$ 8.75	(19%)

Gross general and administrative expenses increased 32% and 27% in the three months and year ended June 30, 2014, respectively, compared to the same periods in 2013 primarily due to a general increase in costs required to support expanded operations. General and administrative expenses have decreased by 16% and 19% on a per boe basis in the three months and year ended June 30, 2014, respectively, compared to the same periods in 2013 primarily as a result of increased production period over period.

Net Finance Income and Expense

	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Net financing expense paid	**$ 1,970**	$ 6,365	(69%)	**$ 6,679**	$ 8,213	(19%)
Non-cash financing costs	**1,121**	3,958	(72%)	**2,977**	7,337	(59%)
Net finance expense	**$ 3,091**	$ 10,323	(70%)	**$ 9,656**	$ 15,550	(38%)

Net finance expense paid decreased by 70% and 38% in the three months and year ended June 30, 2014, respectively, compared the same periods in 2013 due to a one-time restructuring cost incurred on the prepayment of the $45 million Shona Term Loan in the three months ended June 30, 2013, offset by increased interest and financing costs incurred on the $220 million (2013 - $140 million) Senior Secured Term Loan.

Commodity Contracts

At June 30, 2014, the Corporation had one financial oil collar outstanding under the following terms:

Period	Volume	Type	Price Range
Jan 2014 – Dec 2014	500 bbls/day	Financial Brent Oil Collar	$75.00 – $123.50

Gains and losses on commodity contracts recognized in net income/loss are summarized below:

	Three months ended June 30,		Year ended June 30,	
	2014	2013	**2014**	2013
Unrealized change in fair value	**$ 5**	$ (1,137)	$ **(242)**	$ (147)
Realized cash settlement	**-**	-	**432**	1,634
Total loss (gain)	**$ 5**	$ (1,137)	$ **190**	$ 1,487

Stock-Based Compensation Expense

	Three months ended June 30,			Year ended June 30,		
	2014	2013	Change	**2014**	2013	Change
Gross costs	**$ 5,704**	$ 1,900	200%	**$ 10,528**	$ 8,024	31%
Less: capitalized amounts	**(1,750)**	(926)	89%	**(3,370)**	(3,575)	(6%)
Stock-based compensation expense	**$ 3,954**	$ 974	306%	**$ 7,158**	$ 4,449	61%

Stock-based compensation expense is a non-cash expense that is based on the fair value of stock options granted. The fair value is calculated on grant date and amortized over the vesting period.

Restricted Share Units

	Number (000s)	Amount
Balance at June 30, 2013	1,404	$ 3,914
Granted	62	366
Settled	(1,404)	(7,232)
Unrealized loss	-	3,647
Foreign exchange gain	-	(291)
Balance at June 30, 2014	**62**	$ **404**

On May 2, 2013, the Corporation granted 1,404,138 restricted share units ("RSUs") to certain directors, officers and employees, with a reference price of C$2.58 per share. These RSUs vested as to one-third in three months and two-thirds in twelve months from the grant date, and were settled in cash. During the year ended June 30, 2014, the Corporation granted 62,082 RSUs to certain employees with a weighted average reference price of C$6.35 per share. These RSUs vest as to one-half in one year and one-half in two years from the grant date, and are settled in cash.

On August 3, 2013 and May 3, 2014, 468,043 and 936,095 restricted share units vested and were settled in cash, respectively.

Depletion and Depreciation Expense

	Three months ended June 30, 2014	2013	Change	Year ended June 30, 2014	2013	Change
Depletion and depreciation expense	**$ 14,897**	$ 12,325	21%	**$ 38,740**	$ 46,910	(17%)
$/boe	**$ 13.28**	$ 16.35	(19%)	**$ 10.14**	$ 18.45	(45%)

Depletion and depreciation expense increased 21% in the three months ended June 30, 2014 compared to 2013 primarily as a result of the higher depletable base at LLA-23. Depletion and depreciation expense decreased 17% in the year ended June 30, 2014 compared to 2013 primarily as a result of the lower depletable base at Rancho Hermoso after an impairment charge was recognized in the three months ended June 30, 2013.

Impairment on Development Assets

	Three months ended June 30, 2014	2013	Year ended June 30, 2014	2013
Impairment on development assets	**$ 10,577**	$ 106,755	**$ 10,577**	$ 106,755

At June 30, 2014, a write down of $10.6 million (2013 – $106.8 million) was recorded based on the estimated recoverable amount of the Rancho Hermoso CGU, representing the value in use using a 10% (2013 – 25%) discounted cash flow of reserves as determined by the Corporation's external reserve evaluators and the then current forecast prices for crude oil. The Rancho Hermoso field is a mature field that in fiscal 2013 through fiscal 2014 experienced a decline in its production, resulting in reduced field economics. The Corporation intends to manage the Rancho Hermoso operation with the objective to maintain profitable operations and maximize free cash flows until it reaches its economic limit. Other producing fields with reserves assigned were unaffected.

Income Tax Expense

	Three months ended June 30, 2014	2013	Year ended June 30, 2014	2013
Current income tax expense	**$ 11,030**	$ 1,206	**$ 24,823**	$ 2,033
Deferred income tax expense (recovery)	**(6,115)**	(43,287)	**(2,807)**	(44,140)
Income tax expense (recovery)	**$ 4,915**	$ (42,081)	**$ 22,016**	$ (42,107)

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 34%.

Cash and Funds from Operations and Net Income (Loss)

	Three months ended June 30, 2014	2013	Change	Year ended June 30, 2014	2013	Change
Cash provided by (used in) operating activities	**$ 8,715**	$ 21,739	(60%)	**$ 77,944**	$ 26,055	199%
Per share – basic ($)	**$ 0.09**	$ 0.25	(64%)	**$ 0.87**	$ 0.35	149%
Per share – diluted ($)	**$ 0.09**	$ 0.25	(64%)	**$ 0.86**	$ 0.35	146%
Adjusted funds from operations (1)	**$ 23,371**	$ 19,102	22%	**$ 95,522**	$ 51,153	87%
Per share – basic ($)	**$ 0.24**	$ 0.22	9%	**$ 1.06**	$ 0.68	56%
Per share – diluted ($)	**$ 0.23**	$ 0.22	5%	**$ 1.06**	$ 0.68	56%
Net income (loss)	**$ (2,070)**	$ (119,046)	(98%)	**$ 9,937**	$ (127,807)	n/a
Per share – basic ($)	**$ (0.02)**	$ (1.38)	(99%)	**$ 0.11**	$ (1.71)	n/a
Per share – diluted ($)	**$ (0.02)**	$ (1.38)	(99%)	**$ 0.11**	$ (1.71)	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 June 30,		Year ended June 30,	
	2014	2013	**2014**	2013
Drilling and completions	**$ 27,662**	$ 7,965	**$ 68,143**	$ 23,499
Facilities, work overs and infrastructure	**3,207**	1,526	**12,193**	10,247
Property acquisition (divestitures)	**40,000**	(4,496)	**55,000**	(9,887)
Seismic, capitalized general and administrative expenses, capitalized borrowing costs and other	**6,224**	8,101	**17,829**	26,681
Net capital expenditures	**77,093**	13,096	**153,165**	50,540
Ecuador	**10,491**	2,659	**34,944**	17,268
Adjusted net capital expenditures (1) (2)	**$ 87,584**	$ 15,755	**$ 188,109**	$ 67,808
Net capital expenditures recorded as:				
Expenditures on exploration and evaluation assets	**$ 12,732**	$ 4,897	**$ 42,108**	$ 18,564
Expenditures on property, plant and equipment	**64,361**	8,199	**111,057**	31,976
Net capital expenditures (2)	**$ 77,093**	$ 13,096	**$ 153,165**	$ 50,540

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

Capital expenditures in fiscal Q4 2014 primarily related to:

- Drilling, completion and facilities costs at LLA-23 (Labrador, Leono and Pantro);
- Drilling costs at Santa Isabel (Morsa);
- Civil work and facilities costs at Esperanza (Palmer);
- Drilling and completion costs at VMM-2 (non-operated);
- Drilling, completion and facilities costs at Capella (non-operated); and
- Drilling, completion and recompletion costs related to the Ecuador IPC (accounted for under the equity method of accounting)

Effective as of June 1, 2014, the Corporation acquired an additional 10% working interest in the LLA 23 contract for a purchase price of $40 million, payable in cash and the assumption of certain liabilities related to the LLA23 contract, subject to certain post-closing adjustments relating to unbilled expenditures attributable to the acquired interest prior to the date of the transaction.

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 common share capital, convertible debentures, bank debt and working capital, defined as current assets less current liabilities, excluding non-cash items such as the current portion of commodity contracts, current portion of warrants, current portion of convertible debentures and any embedded derivatives asset/liability. 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 the ratio of net debt to adjusted funds from operations. This ratio is calculated as net debt, defined as the principal amount of its outstanding bank debt plus the principal amount of its convertible debentures, unless the debentures are in-the-money or may otherwise be settled in common shares at the option of the Corporation, less working capital, as defined above and less the current portion of bank debt and convertible debentures included above, divided by adjusted funds from operations. The Corporation uses the ratio of net debt to adjusted funds from operations as a key indicator of the Corporation's leverage and to monitor the strength of its financial position.

In order to facilitate the management of this ratio, 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.

		June 30, 2014
Bank debt (current and long-term) – principal	$	220,000
Working capital surplus, excluding the current portion of bank debt and derivatives		(159,117)
Net debt	$	60,883
Adjusted funds from operations (1)	$	95,522
Net debt to adjusted funds from operations		0.6

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

Credit Facilities and Debt

Senior Secured Term Loan

On April 3, 2013, the Corporation entered into a credit agreement for a $140 million senior secured term loan with a syndicate of banks. The Senior Secured Term Loan was for a five-year term, with interest payable quarterly and principal repayable in 15 equal quarterly instalments starting in October 2014, following an initial 18 month grace period. The Senior Secured Term Loan carried interest at LIBOR plus 4.50% and was secured by all of the material assets of the Corporation.

On April 24, 2014, the Corporation completed an upsizing of its existing Senior Secured Term Loan, from $140 million to $220 million, with no changes to the terms of the Senior Secured Term Loan or the repayment schedule. The revised term loan carries interest at LIBOR plus 4.50-5.00%, depending on agreed leverage ratios, and is secured by all of the material assets of the Corporation. The carrying value of the Senior Secured Term Loan included $9.3 million of transaction costs netted against the principal amount as at June 30, 2014.

The Senior Secured Term Loan includes various non-financial covenants relating to future acquisitions, indebtedness, operations, investments, capital expenditures and other standard operating business convents. The Senior Secured Term Loan also includes various financial covenants, including a maximum consolidated leverage ratio ("Consolidated Leverage Ratio"), a minimum consolidated interest coverage ratio ("Consolidated Interest Coverage Ratio"), a minimum debt service coverage ratio ("Debt Service Coverage Ratio"), a minimum consolidated current assets to consolidated current liabilities ratio ("Consolidated Current Assets to Consolidated Current Liabilities Ratio") and other standard financial covenants.

The Consolidated Leverage Ratio is calculated on a quarterly basis as consolidated total debt ("Consolidated Total Debt") divided by consolidated EBITDAX ("Consolidated EBITDAX"). The maximum allowable Consolidated Leverage Ratio is 2.75:1.00. Consolidated Total Debt includes the principal amount of all indebtedness, which currently includes bank debt, office lease commitments, and net hedging liabilities, if any, and specifically excludes amounts with respect to the Corporation's convertible debentures or warrants; additionally, restricted cash maintained in the debt service reserve account related to the 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 adjusted for interest, income taxes, depreciation, depletion, amortization, exploration expenses, share of joint venture profit/loss and other similar non-recurring or non-cash charges. Consolidated EBITDAX is further adjusted for the contribution to adjusted funds from operations, before taxes, of the results of the Ecuador IPC as disclosed in the calculation of Adjusted Funds from Operations in the Corporation's management's discussion and analysis. 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 consolidated financial statements.

The Consolidated Interest Coverage Ratio is calculated on a quarterly basis as Consolidated EBITDAX divided by consolidated interest expense ("Consolidated Interest Expense"). The minimum Consolidated Interest Coverage Ratio required is 3.50:1.00. 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 includes interest expense, amortization of upfront fees, and capitalized interest.

The Debt Service Coverage Ratio is calculated on a quarterly basis as actual cash collections deposited by customers in the Corporation's collection accounts divided by the debt service amount ("Debt Service Amount"). The minimum Debt Service Coverage Ratio required is 1.50:1.00. The Debt Service Amount is defined as the sum of all amounts in respect of principal, interest, and fees payable on the interest payment date succeeding the date of the calculation.

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. The minimum Consolidated Current Assets to Consolidated Current Liabilities Ratio required is 1.00:1.00.

The Corporation was in compliance with its covenants as at June 30, 2014.

Other Colombian Credit Facilities

The Corporation has revolving lines of credit in place in Colombia with an aggregate borrowing base of $37.4 million (COP$ 70.4 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. The facilities were undrawn as at June 30, 2014.

Letters of Credit

At June 30, 2014, the Corporation had letters of credit outstanding totaling $32.8 million to guarantee work commitments on exploration blocks 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 $15.8 million.

Convertible Debentures

The Corporation has convertible debentures outstanding with a face value of $23.9 million (fair value – $25.4 million) that mature on June 30, 2015, and bear an annual coupon rate of 8%, payable semi-annually. The debentures are convertible into common shares of the Corporation at the option of the holder at a conversion price of C$10.526 per share, being the ratio of 95 common shares per C$1,000 principal amount of the debentures. On the maturity date, the Corporation has a right to repay the outstanding principal amount and any accrued interest in common shares of the Corporation, subject to certain conditions, including customary regulatory approvals.

Share Capital

At September 22, 2014, the Corporation had 107.8 million common shares, 2.5 million warrants, 9.7 million stock options, 0.1 million restricted share units and 2.7 million phantom warrants 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 June 30, 2014:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	44,000	117,336	58,664	220,000
Trade and other payables	75,814	-	-	75,814
Deferred income	-	3,731	-	3,731
Commodity contracts	38	-	-	38
Equity tax payable – undiscounted	587	-	-	587
Other long term obligations	-	-	219	219
Convertible debentures – principal	23,904	-	-	23,904
Phantom warrants	-	7,557	-	7,557
Warrants	2,121	2,210	-	4,331
Restricted share units	202	202	-	404
Exploration and production contracts	22,053	26,842	-	48,895
Office leases	1,045	1,748	3,852	6,645

Exploration and Production Contracts

The Corporation has entered into a number of exploration contracts in Colombia and Peru which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding exploration commitments at June 30, 2014 of $48.9 million and has issued $23.5 million in financial guarantees related thereto. These commitments are planned to be satisfied by means of seismic work, exploration drilling and farm-outs.

Ecuador Incremental Production Contract

In addition to the contractual obligations described above, the Corporation has a non-operated 25% equity participation interest (27.9% capital 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 is committed to incur project expenditures for a total of $334 million ($93.3 million net to the Corporation) over the 15 year term of the contract. As at June 30, 2014, the Corporation had incurred $55.6 million of expenditures in connection with its Ecuador IPC commitment.

Provisions

There is an ongoing disagreement between the Corporation and another Colombian entity (the "Counterparty") over the payment of certain operating costs relating to crude oil production. The Counterparty has asserted that Canacol is liable for certain operating costs incurred by the Counterparty. Canacol disagrees with this assertion because it believes the Counterparty has not met the terms of the contract governing these operating costs. The ultimate result of this disagreement cannot be determined at June 30, 2014.

At June 30, 2013, the Corporation believed that the disagreement may result in a cash settlement and had recorded a provision of $10.5 million based on management's estimate. At June 30, 2014, the Corporation believes that the possibility of an outflow of resources embodying economic benefits to settle this disagreement is remote and has consequently reversed such provision during the year ended June 30, 2014 in accordance with IAS 37.

Detailed information of the estimated provision and the reversal thereof was not disclosed as it may prejudice seriously the position of the Corporation in the disagreement with the Counterparty.

OUTLOOK

In light of its recent exploration successes, for the remainder of calendar 2014 the Corporation plans to continue with its expanded capital program.

On the LLA-23 block, the Corporation has recently added a second drilling rig to its program in order to accelerate the drilling of additional exploration wells, including the remaining two exploration wells at Maltes-1 and Pastor-1, and up to three development wells throughout the remainder of calendar 2014 and into early 2015.

The Corporation also commenced the acquisition of 400 square kilometer 3D seismic in August 2014. The objective of the 3D seismic program is to firm up the portfolio of 12 currently identified exploration leads into prospects for drilling in calendar 2015 and 2016.

On the Esperanza block, upon the completion of testing operations at Palmer-1, the Corporation plans to spud the second of three planned exploration wells targeting the Cienaga de Oro reservoir, Corozo 1, in early October 2014 subject to approval by the ANH. The Corporation plans to commence drilling of the third exploration well, Canandonga-1, in December 2014, subject to approval by the ANH.

In other areas of Colombia, the Corporation and its partner expect to drill an additional appraisal well into the shallow Lisama discovery on the VMM-2 block prior to the end of 2014. The operator of the Capella property is expected to continue its extensive development program for the field through calendar 2014. The Corporation also anticipates the drilling of the Pico Plata-1 exploration well on the VMM-3 block and the Cejudo-1 exploration well on the VMM-2 block in the remainder of calendar 2014 and into 2015.

In Ecuador, the consortium plans to drill five additional new development wells and work over three existing producing wells in the remainder of calendar 2014.

SUMMARY OF QUARTERLY RESULTS

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
Petroleum and natural gas revenues, net of royalties	**61,744**	55,653	42,168	48,222	38,961	34,602	26,200	41,592
Adjusted petroleum and natural gas revenues, net of royalties, including revenues relate to the Ecuador IPC (1)	**68,351**	61,550	45,987	51,622	41,796	36,725	27,350	41,795
Cash provided by operating activities	**8,715**	13,099	36,406	19,724	13,829	(8,520)	6,445	6,391
Per share – basic	**0.09**	0.15	0.42	0.23	0.16	(0.10)	0.10	0.10
Per share – diluted	**0.09**	0.15	0.41	0.23	0.16	(0.10)	0.10	0.10
Adjusted funds from operations (1) (3)	**23,371**	32,274	15,599	24,278	19,102	15,578	3,202	14,072
Per share – basic (1)	**0.24**	0.36	0.18	0.28	0.22	0.18	0.05	0.23
Per share – diluted (1)	**0.23**	0.35	0.18	0.28	0.22	0.18	0.05	0.23
Net income (loss)	**(2,070)**	19,438	(10,412)	2,981	(119,046)	(3,425)	1,820	(7,156)
Per share – basic	**(0.02)**	0.22	(0.12)	0.03	(1.38)	(0.04)	0.03	(0.12)
Per share – diluted	**(0.02)**	0.21	(0.12)	0.03	(1.38)	(0.04)	0.03	(0.12)
Capital expenditures, net	**77,093**	35,915	22,749	17,408	13,099	3,021	19,431	14,971
Adjusted capital expenditures, net, including capital expenditures related to the Ecuador IPC (1)	**87,584**	44,103	32,679	23,743	15,758	10,434	22,667	18,931
Operations (boepd)								
Petroleum and natural gas **production**, before royalties								
Petroleum (2)	**9,271**	8,260	6,998	6,110	5,390	4,785	5,035	6,021
Natural gas	**2,941**	2,633	3,097	3,022	2,879	2,874	319	-
Total (2)	**12,212**	10,893	10,095	9,132	8,269	7,659	5,354	6,021
Petroleum and natural gas **sales**, before royalties								
Petroleum (2)	**9,386**	8,792	5,868	6,307	5,372	4,267	4,815	7,322
Natural gas	**2,937**	2,626	2,953	3,052	2,914	2,874	319	-
Total (2)	**12,323**	11,418	8,821	9,359	8,286	7,141	5,134	7,322

(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.
(3) Included in adjusted funds from operations for the three months ended June 30, 2014 were cash outflows totalling $10.6 million related to the final payment under the May 2013 RSU grant and other non-recurring settlements. Without such outflows, adjusted funds from operations were $34.0 million on a pro forma basis.

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.

Much of the Corporation's revenues and exploration and development costs are expected to be received/paid in reference to United States dollar ("US dollar") denominated prices while a significant portion of its operating and general and administrative costs are denominated in Canadian dollars and Colombian Pesos. The Colombian Peso has seen significant variation against the US dollar in the past and it continues to have significant daily fluctuations. 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. The Corporation had no interest rate swap or financial contracts in place as at or during the years ended June 30, 2014 and 2013.

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.

During the year ended June 30, 2014, the Corporation had three financial oil collars under the following terms:

Period	Volume	Type	Price Range
Jan 2014 – Dec 2014	500 bbls/day	Financial Brent Oil Collar	$75.00 – $123.50
Jul 2013 – Dec 2013	500 bbls/day	Financial Brent Oil Collar	$85.00 – $107.50
Jul 2013 – Dec 2013	500 bbls/day	Financial Brent Oil Collar	$85.00 – $106.80

The fair value of these transactions is based upon the estimated amounts that would have been paid to or received from counter parties in order to settle the transactions outstanding with reference to the forward prices as of the reporting date. The contracts have been transacted with a counter party with whom management has assessed credit risk and deemed no adjustment for credit risk is required in determining the estimated settlement price. In addition, the contracts are based on standard industry contracts and the Corporation does not feel that there is a liquidity risk associated with them and no adjustment has been recorded in computing their valuation. While commodity contract activities may have opportunity costs when realized prices exceed commodity contract pricing, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such techniques.

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. In Colombia, a significant portion of crude oil sales and tariff oil revenue are with customers that are directly or indirectly controlled by the government.

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 June 30, 2014 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

A detailed discussion of new accounting policies that affect the Corporation is provided in the notes to the financial statements.

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 annual certificates required to be filed under National Instrument 52-109. In addition to the processes that specifically fall into the category of DC&P, the Corporation has also adopted a company-wide Corporate Disclosure Policy and has additional procedures in place to provide reasonable assurance that any material information required to be disclosed by the Corporation in its annual filings is recorded, processed, summarized and reported within the time periods specified in securities legislation. With the assistance of expert advisors and other members of management, the Corporation's CEO and CFO have assessed the design and operating effectiveness of the Corporation's DC&P as at June 30, 2014 and have not identified any material weaknesses relating to the design or operating effectiveness of the Corporation's DC&P framework.

Internal Control 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. With the assistance of expert advisors and other members of management, the Corporation's CEO and CFO have assessed the design and operating effectiveness of the Corporation's ICFR as at June 30, 2014, using the framework and criteria established in Internal Control – Integrated Framework ("1992 COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and have not identified any material weaknesses relating to the design or operating effectiveness of the Corporation's ICFR framework.

During the quarter ended June 30, 2014, 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.