CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE AND NINE MONTHS ENDED MARCH 31, 2012

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial	Three months ended March 31, 2012	2011	Change	Nine months ended March 31, 2012	2011	Change
Crude oil sales, net of royalties	**34,481**	23,452	47%	**101,875**	54,340	87%
Tariff revenue	**14,151**	8,677	63%	**37,328**	11,468	225%
Total revenues	**48,632**	32,129	51%	**139,203**	65,808	112%
Funds from operations (1)	**20,042**	13,518	48%	**59,320**	23,863	149%
Per share – basic ($)	**0.03**	0.03	-	**0.11**	0.05	120%
Per share – diluted ($)	**0.03**	0.03	-	**0.10**	0.05	100%
Net income (loss)	**3,663**	(852)	n/a	**14,726**	(45,837)	n/a
Per share – basic and diluted ($)	**0.01**	-	-	**0.03**	(0.10)	n/a
Capital expenditures	**52,424**	20,665	154%	**146,205**	51,309	185%
				March 31, 2012	June 30, 2011	Change
Cash and cash equivalents				**58,969**	101,627	(42%)
Restricted cash				**9,103**	13,048	(30%)
Net working capital surplus (1)				**43,727**	94,547	(54%)
Total assets				**430,471**	316,570	36%
Common shares, end of period (000s)				**623,563**	511,637	22%

Operating	Three months ended March 31, 2012	2011	Change	Nine months ended March 31, 2012	2011	Change
Crude oil production (bopd)						
Tariff	**8,917**	7,023	27%	**8,118**	3,092	163%
NRI	**4,246**	2,935	45%	**3,982**	2,333	71%
Total	**13,163**	9,958	32%	**12,100**	5,425	123%
Crude oil sales (bopd)						
Tariff	**8,958**	6,899	30%	**8,120**	3,006	170%
NRI	**3,784**	3,161	20%	**4,008**	2,211	81%
Total	**12,742**	10,060	27%	**12,128**	5,217	132%
Rancho Hermoso – tariff oil operating netback ($/bbl) (1)						
Realized tariff oil price	**17.36**	13.97	24%	**16.72**	13.92	20%
Operating and transportation costs	**(5.52)**	(3.14)	76%	**(6.36)**	(4.01)	59%
RH tariff oil operating netback	**11.84**	10.83	9%	**10.36**	9.91	5%
Rancho Hermoso – non-tariff (NRI) oil operating netback ($/bbl) (1)						
Realized crude oil price, net of royalties	**101.70**	83.02	23%	**93.60**	92.22	1%
Operating and transportation costs	**(39.69)**	(23.06)	72%	**(35.27)**	(29.37)	20%
RH NRI oil operating netback	**62.01**	59.96	3%	**58.33**	62.85	(7%)

(1) Non-IFRS measure. See “Non-IFRS Measures” section within MD&A.

Financial Highlights for the Three and Nine Months Ended March 31, 2012

Canacol Energy Ltd. ("Canacol" or the "Corporation") completed a successful quarter in fiscal Q3 2012. Highlights include:

- Total revenues for the three months ended March 31, 2012 increased 51% to $48.6 million from $32.1 million for the comparable period. Total revenues for the nine months ended March 31, 2012 increased 112% to $139.2 million from $65.8 million for the comparable period.
- Funds from operations for the three months ended March 31, 2012 increased 48% to $20.0 million from $13.5 million for the comparable period. Funds from operations for the nine months ended March 31, 2012 increased 149% to $59.3 million from $23.9 million for the comparable period. Funds from operations were reduced by a one-time settlement of a legal claim in the third quarter of 2012 for $1.6 million.
- Net income for the three months ended March 31, 2012 was $3.7 million, compared to a net loss of $0.9 million for the comparable period. Net income for the nine months ended March 31, 2012 was $14.7 million, compared to a net loss of $45.8 million for the comparable period.
- Capital expenditures for the three and nine months ended March 31, 2012 were $52.4 million and $146.2 million, respectively.
- Average daily sales volumes increased 27% to 12,742 barrels of oil per day ("bopd") for the three months ended March 31, 2012 compared to 10,060 bopd for the comparable period. For the nine months ended March 31, 2012, average daily sales volumes increased 132% to 12,128 bopd compared to 5,217 bopd for the comparable period. For the three and nine months ended March 31, 2012 the Corporation's production was affected by a number of electro-submersible pump and injection pump failures, consequently resulting in reduced sales volumes during the periods. These production issues have been resolved and the Corporation reiterates its calendar 2012 production guidance of between 14,000 and 16,000 bopd of net revenue production.
- For the three months ended March 31, 2012, the Corporation's operating netback for Rancho Hermoso non-tariff (NRI) production was $62.01/bbl and for Rancho Hermoso tariff production was $11.84/bbl. For the nine months ended March 31, 2012, the Corporation's operating netbacks were $58.33/bbl for Rancho Hermoso non-tariff (NRI) production and $10.36/bbl for Rancho Hermoso tariff production.
- The Corporation had $68.1 million in cash, cash equivalents and restricted cash, and $43.7 million of working capital surplus at March 31, 2012.

OPERATIONAL UPDATE

Capital Program and Corporate Guidance for Calendar 2012

In late December 2011, the Corporation announced its calendar 2012 capital program of $150.0 million for exploration and development activities in Colombia, Brazil and Guyana. The budget includes the drilling of 40 gross wells (16 net wells), which consists of 26 gross development wells and 14 gross exploration wells. The budget also includes the acquisition of 740 km and 361 square km of 2D and 3D seismic, respectively, and the expansion of facilities at the Corporation's operated Rancho Hermoso field. In total, the Corporation plans to spend approximately $88 million for exploration programs in Colombia, Brazil and Guyana, and $62.0 million for production programs in Colombia in calendar 2012. The budget meets the Corporation's exploration drilling and seismic acquisition work program commitments for calendar 2012.

The Corporation's production guidance for calendar 2012 is expected to average between 14,000 and 16,000 bopd, net after royalties. This guidance excludes any production from potential future exploration successes.

Llanos Basin, Colombia

Rancho Hermoso Field (operator, 100% working interest)

In April 2012, the Corporation completed the drilling of the Rancho Hermoso 16 ("RH 16"). The well was tested at a stable gross rate of 5,160 bopd from the Mirador reservoir, and is currently on permanent production. The Gacheta reservoir in the RH 16 well was also tested at a stable gross rate of 398 bopd. The Gacheta reservoir is a new oil-producing reservoir identified in the field for which no reserves are currently assigned. In addition, the Rancho Hermoso 6 ("RH 6") well was recompleted in the Mirador reservoir and was tested at a stable gross rate of 5,397 bopd, and is currently on permanent production.

In March 2012, the Corporation completed the drilling, casing, completion and tie-in of the Rancho Hermoso 15 and 17 ("RH 15" and "RH 17", respectively) development wells.

The RH 15 well was drilled approximately two kilometres to the west of the nearest producing well to test the western limit of the oil-bearing reservoirs within the field.

The RH 17 well was placed on permanent production from the Mirador reservoir at a stabilized gross rate of approximately 5,800 bopd. The well encountered 158 feet of net oil pay within six different reservoir intervals, which include from top to bottom, the C7, Mirador, Los Cuervos-Barco, Guadalupe, Gacheta, and Ubaque.

In January 2012, the Corporation completed the drilling and casing of the Rancho Hermoso 14 ("RH 14") development well. The well was placed on permanent production from the Ubaque reservoir at a stabilized gross rate of 7,666 bopd. The RH 14 well encountered 125 feet of net oil pay within five different reservoir intervals, which include, from top to bottom, the C7, Mirador, Los Cuervos-Barco, Guadalupe, and Ubaque.

LLA 23 E&P contract (80% working interest)
LLA 10 E&P contract (39% working interest)
Caño Los Totumos E&P contract (51% working interest)
Morichito E&P contract (15% working interest)
Entrerrios production contract (operator, 60% working interest)

For calendar 2012, the Corporation plans to re-enter the Agueda 1 well on the LLA 23 contracts, as well as drilling three light oil exploration wells and acquiring seismic on the Caño Los Totumos, LLA 10 and LLA 23 contracts. In March 2012, the Corporation successfully re-entered the Agueda-1 well and tested formation water from two sandstone reservoirs in the C7 reservoir, located on the LLA 23 E&P contract. The Agueda-1 well was drilled in 2007 and bypassed oil pay was identified by the Corporation within the C7 reservoir. Two of the three C7 sandstone reservoirs were perforated between 8,803 – 8,817 and 8,886 – 8,904 feet measured depth and tested in the well, with each zone producing formation water at high rates. The Agueda-1 well has been suspended as a potential future water injection well should the Corporation realize exploration success in any of the exploration prospects the Corporation plans to drill on the LLA 23 E&P contract later in calendar 2012.

In February 2012, the Corporation acquired an additional 9% interest in the LLA 23 block and an additional 10% interest in the Santa Isabel block for a total consideration of $4.5 million paid in common shares of the Corporation.

The Corporation plans to dispose of part or all of its working interests in the Caño Los Totumos, LLA 10, and Morochito E&P contracts, along with its interest in the Entrerrios production contract, which are all considered immaterial to its portfolio. The Corporation anticipates disposing of the assets by the end of calendar third quarter of 2012.

Caguan-Putumayo Basin, Colombia

Ombu E&P Contract – Capella heavy oil discovery (10% working interest)
Cedrela E&P Contract (operator, 100% working interest)
Portofino E&P Contract (40% working interest)
Sangretoro E&P Contract (operator, 100% working interest)
Tamarin E&P Contract (operator, 100% working interest)

In the fiscal third quarter of 2012, the Corporation has participated in the drilling and completion of two horizontal wells, Capella R53H and Capella R55H. The Capella R53H well was tested at a stable rate of 288 gross bopd with a 0.7% water cut, and the Capella R55H well was tested at a stable rate of 242 gross bopd with a 4% water cut. Two rigs are presently active in the field and have recently completed the drilling of Capella L17H and R56H, both of which are horizontal wells. The Capella L17H well reached total depth of 5,050 feet measured depth in early March 2012. The Capella R56H well reached a total depth 4,855 feet measured depth in late March 2012.

Andaquies E&P Contract (36% working interest)
Coati E&P Contract (40% working interest)

In March 2012, C&C Energia Ltd. (the "Operator") finished the drilling and testing of the Tardigrado-1 exploration well in the Andaquies E&P contract and has subsequently abandoned the well. The Tardigrado-1 well encountered 60 feet of sandstone from the Caballos reservoir with an average porosity of 19%. The Caballos reservoir was perforated and tested in the intervals from 4,413 to 4,430 feet and between 4,442 to 4,445 feet. Swab tests from both intervals produced fresh water with slight traces of oil.

The Tardigrado-1 well data indicates that oil shows from the Caballos reservoir may represent a residual oil accumulation in a structure that was flushed by fresh water after the original oil was trapped in the structure. The Operator and the Corporation will determine the future exploration plans for the Andaquies E&P contract after evaluation of all drilling and seismic data.

In February 2012, the Operator finished the completion and testing of the Neme formation in the Cachalote-1 well in the Andaquies E&P contract and has subsequently abandoned the well. The Cachalote-1 well encountered 271 feet of Neme sandstone that contained oil shows over an interval of approximately 130 feet with average porosity of 21%. The Neme reservoir was perforated in the intervals from 5,676 to 5,718 feet measured depth and from 5,642 to 5,660 feet measured depth on a swab test flowed from the lower perforations traces of oil with a gravity of 13.8° API and fresh water at rate of 1,280 barrels of water per day ("bwpd"). The upper perforations tested traces of oil and 1,020 bwpd.

For calendar 2012, the Corporation intends to participate in the drilling of one additional exploration well on the Coati E&P contract, expected later in the fourth quarter of calendar 2012.

Middle Magdalena Basin, Colombia

Santa Isabel E&P Contract (100% working interest)
VMM 2 E&P Contract (40% working interest, reduced to 20% subsequent to March 31, 2012)
VMM 3 E&P Contract (20% working interest)

In April 2012, the Corporation's wholly owned subsidiary, Carrao Energy Sucursal Colombia, entered into a farm-out agreement with ExxonMobil Exploration Colombia Limited, a wholly-owned subsidiary of ExxonMobil Corporation ("ExxonMobil") for the exploration of the Corporation's non-operated VMM 2 E&P contract.

Pursuant to the terms of the agreement, ExxonMobil will carry the cost of the drilling and testing of up to three wells to test conventional and unconventional targets in the La Luna and Rosablanca formations. The first two wells will be vertical wells, while the third well will possibly be a horizontal multi-stage fractured well. It is anticipated that prospective intervals of the La Luna and Rosablanca will be cored and logged within the first well, and stimulated and flow tested within the second well. Should ExxonMobil choose to proceed with a third well, it will possibly be a horizontal multi-stage fractured well. Under the terms of the agreement, ExxonMobil will pay 100% of the cost of the three wells, up to a cap of gross $15.0 million for each of the first 2 wells, and a cap of gross $17.5 million for the third well should it be a horizontal lateral well exceeding 4,000 feet in lateral length, and $15.0 million should it be another vertical well. ExxonMobil will also pay the Corporation $2.2 million upon execution of the farm-out agreement for back-costs related to the acquisition of 3D seismic on the block in 2011. The total potential investment on the block is approximately $50.0 million. In return, ExxonMobil shall earn 50% of the Corporation's 40% interest in the contract. The current operator will remain as operator of VMM 2 during the exploration period and expects to spud the first exploration well in late 2012. The formal assignment of working interests as contemplated by the transaction, including the Corporation's 20% interest, remains subject to the approval of the Agencia Nacional de Hidrocarburos (ANH) of Colombia.

In January 2012, Shell-Colombia acquired 100% participating interest in the VMM 3 E&P contract. Shell-Colombia has assumed approximately $50.0 million in present and future work commitments, which consist of all costs for seismic acquisition and the drilling of three exploratory wells. Effective 2014, the Corporation has the option to exercise a 20% participating interest in the VMM 3 E&P contract for no additional cost.

The Corporation's zero cost option to exercise a 20% participating interest in the VMM 3 E&P contract allows the Corporation to not only retain a significant interest in VMM 3's deep cretaceous potential, but also benefit from having a world-class operator such as Shell-Colombia exploring the area. In addition, the Corporation aims to capture valuable information from Shell-Colombia's activities to de-risk the exploration and development of the Corporation's 100%-operated interest in the adjacent Santa Isabel E&P contract.

The Corporation retains 100% interest in the Santa Isabel E&P contract, and plans to drill one exploration well in the second half of 2012. Should the Cretaceous shale exploration wells in the adjacent VMM 2 and VMM 3 prove successful, the Corporation has retained significant exposure and upside to the play on its 100% owned Santa Isabel E&P contract.

Upper Magdalena Basin, Colombia

COR-11 E&P Contract (operator, 70% working interest)
COR-39 E&P Contract (operator, 70% working interest)

For calendar 2012, the Corporation plans on the acquisition of 260 km of 2D seismic followed by drilling of each of the contracts in 2013.

Brazil and Guyana

Brazil REC-T-170 (operator, 100% working interest)
Guyana Takutu PPL (operator, 70% working interest)

In the second half of calendar 2012, the Corporation plans to drill one exploration well at REC-T-170 in the Reconcavo basin, Brazil. With the recent move into Ecuador, both Brazil and Guyana are considered non-core for the Corporation. The Corporation is in advanced negotiations with a potential partner to farm-out 50% of its 100% operated working interest in the REC-T-170 block, with the transaction anticipated to close prior to the end of the third quarter 2012. The Corporation also plans to farm-out all or part of its working interest in the Takutu PPL in 2012 and is currently reviewing bids from interested parties.

Ecuador

Libertador (25% working interest)
Atacapi (25% working interest)

In February 2012, PARDALISERVICES S.A., a company established by Tecpetrol International S.A. (the "Operator"), Schlumberger Ltd., Sertecpet S.A., and Canacol was awarded a 15 year incremental production contract by the national oil company of Ecuador ("Petroecuador" or "EPPE") for the Libertador and Atacapi mature fields in Northern Ecuador. The Corporation has a non-operated 25% equity participation in the project.

The Operator is required to spend a total of $334 million ($92.9 million, net to the Corporation) for the drilling of 31 new development wells and the workover of 28 existing wells over the 15-year period of the contract. In return for increased production at EPPE's mature fields, the Operator will receive a fixed price tariff of $39.56 for each incremental barrel produced, which is insensitive to oil price fluctuations.

In addition to absorbing all operating costs at the Libertador and Atacapi fields, EPPE will continue to manage regular operations, licensing and permits, and relations with communities and the local government. The Operator will supervise base curve production and assist EPPE with potentially reducing operating expenses at both fields. The value of any success achieved will be split 50/50 between EPPE and PARDALISERVICES S.A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. (the "Corporation") and its subsidiaries are primarily engaged in petroleum and natural gas exploration and development activities in Colombia, Brazil and Guyana. 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 and the Bolsa de Valores de Colombia under the symbol CNE.C.

Advisories

The following management's discussion and analysis ("MD&A") is dated May 14, 2012 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 March 31, 2012 and 2011 (the "interim financial statements"), and the audited consolidated financial statements and management's discussion and analysis for the year ended June 30, 2011. In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS") and requires publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Previously, the Corporation prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The interim financial statements have been prepared in accordance with IFRS and all amounts herein are in United States dollars, unless otherwise noted, and all tabular amounts are 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, and 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 *– One of the benchmarks the Corporation uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in IFRS that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and decommissioning obligation expenditures. The Corporation considers 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. 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 funds from operations may not be comparable to that reported by other companies. The Corporation also presents 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 funds from operations:*

	Three months ended March 31,		Nine months ended March 31,	
	2012	2011	**2012**	2011
Cash provided by operating activities	**$ 19,662**	$ 1,686	**$ 82,593**	$ 19,571
Changes in non-cash working capital	**380**	11,832	**(23,273)**	4,292
Funds from operations	**$ 20,042**	$ 13,518	**$ 59,320**	$ 23,863

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, including the current portion of any principal amount of convertible debentures, assuming they are out-of-the-money and not repayable in shares at maturity, 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 crude oil sales, net of royalties, less operating and transportation expenses, calculated on a per barrel basis of sales volumes. 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.

IFRS

The accounting policies of the Corporation have been adjusted to comply with IFRS beginning with the balance sheet as at July 1, 2010. A comprehensive summary of all of the significant changes, including reconciliations of Canadian GAAP financial statements to those prepared under IFRS, is presented in note 24 "Transition to IFRS" of the Corporation's interim financial statements as at and for the three and nine months ended March 31, 2012.

The adoption of IFRS did not impact the cash the Corporation generated; however, it did have an impact on the Corporation's statement of financial position and statement of operations and comprehensive income (loss). A reconciliation of the previously reported net loss for the three and nine months ended March 31, 2011, from Canadian GAAP to IFRS is provided below:

	Three months ended March 31, 2011	Nine months ended March 31, 2011
Net loss under Canadian GAAP, as previously reported	$ 3,343	$ 19,780
Depletion and depreciation	(2,175)	(6,333)
Income tax expense	428	943
Net finance (income) expense	(252)	824
Impairment loss on Brazilian assets	-	2,069
Foreign exchange (gain) loss	1,687	3,296
(Gain) loss on convertible debentures	(2,079)	25,558
Stock-based compensation	(100)	(300)
Net loss under IFRS	**$ 852**	**$ 45,837**

RESULTS OF OPERATIONS

Overview

The Corporation's primary producing property is the Rancho Hermoso field in Colombia. Production from Rancho Hermoso falls under either: i) "non-tariff", "net revenue interest" or "NRI" production, 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 NRI production is derived from the remaining formations, including the Ubaque, Guadalupe, Barco Los Cuervos and Carbonera.

Tariff revenues relate to 100% of the gross sales of tariff oil and the Corporation reports gross tariff sales volumes in this MD&A. NRI revenues relate to only the Corporation's net revenue interest in such sales volumes, which are reported in this MD&A net after royalties. The production sharing contract for NRI oil requires the Corporation to pay 100% of the gross operating costs with respect to NRI production from the field. Consequently, when analyzing per barrel operating costs and operating netbacks, it is important for readers to understand that 100% of gross operating costs are being included in the numerator of this calculation, while only the Corporation's net revenue interest of sales volumes is used in the denominator. This makes comparison of operating costs per barrel and operating netbacks between tariff oil and NRI oil more difficult without considering gross sales volumes. Consequently, the Corporation has provided additional information with respect to gross sales volumes for the Rancho Hermoso field to assist the reader with these metrics.

The Corporation also has minor production from its Capella and Entrerrios properties in Colombia. Sales volumes from these properties are reported in this MD&A net after royalties, the same as NRI oil.

In addition to its producing fields, the Corporation has significant interests in a number of exploration blocks in Colombia, Brazil and Guyana as well as an incremental production contract in Ecuador. A more detailed discussion of these blocks and the commitment related thereto is provided further below in this MD&A.

Business Acquisition

In November 2011, the Corporation entered into an agreement to acquire all of the issued and outstanding shares of Carrao Energy Ltd. ("Carrao"), a private company engaged in the evaluation, acquisition, exploration and development of oil and gas properties in Colombia.

On November 29, 2011, the closing date of the transaction, the Corporation acquired approximately 96% of the issued and outstanding securities of Carrao through the issuance of an aggregate 99,930,109 common shares of the Corporation to former holders of Carrao shares, warrants and stock options. The closing price of the Corporation's common shares on the closing date was C$0.64 per share. On January 30, 2012, the Corporation issued a further 4,806,445 common shares to acquire the remaining 4% interest in accordance with the compulsory acquisition provisions of the *Business Corporations Act* (British Columbia).

Average Daily Crude Oil Production and Sales Volumes – Barrels of Oil per Day (“bopd”)

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Gross production (Rancho Hermoso only)						
Rancho Hermoso – tariff	**8,917**	7,023	27%	**8,118**	3,092	163%
Rancho Hermoso – non-tariff	**18,829**	12,317	53%	**16,391**	9,309	76%
	27,746	19,340	43%	**24,509**	12,401	98%
Production, net after royalties						
Rancho Hermoso – tariff	**8,917**	7,023	27%	**8,118**	3,092	163%
Rancho Hermoso – non-tariff (NRI)	**4,046**	2,716	49%	**3,789**	2,120	79%
	12,963	9,739	33%	**11,907**	5,212	128%
Other	**200**	219	(9%)	**193**	213	(9%)
Production, net after royalties	**13,163**	9,958	32%	**12,100**	5,425	123%
Inventory movements and adjustments	**(421)**	102	n/a	**28**	269	(90%)
Sales, net after royalties	**12,742**	10,060	27%	**12,128**	5,694	113%
Gross sales (Rancho Hermoso only)						
Rancho Hermoso – tariff	**8,958**	6,899	30%	**8,120**	3,006	170%
Rancho Hermoso – non-tariff	**18,359**	12,190	51%	**16,416**	9,134	80%
	27,317	19,089	43%	**24,537**	12,140	102%
Sales, net after royalties						
Rancho Hermoso – tariff	**8,958**	6,899	30%	**8,120**	3,006	170%
Rancho Hermoso – non-tariff (NRI)	**3,576**	2,938	22%	**3,814**	1,998	91%
	12,534	9,837	27%	**11,935**	5,004	139%
Other	**208**	223	(7%)	**193**	213	(9%)
Sales, net after royalties	**12,742**	10,060	27%	**12,128**	5,217	132%

The increase in production at Rancho Hermoso reflects the Corporation’s continued success with its development drilling program, offset by natural production declines. This drilling program has resulted in the Corporation producing from 14 wells in the third quarter of 2012 compared to 9 wells for the comparable period. The Corporation’s production was however affected in the third quarter of 2012 by a number of electro-submersible pump and injection pump failures, consequently resulting in reduced production levels during the period.

Rancho Hermoso tariff production increased 27% from the third quarter of 2011 to 2012 and 163% from the nine months ended March 31, 2011 to 2012, primarily due to production from RH 8. RH 8 initially came on production from the Barco Los Cuervos formation but was converted to a Mirador well and commenced production in October 2011at an initial rate of approximately 4,200 bopd. The increase is also attributable to the production from RH 17, which came on production at the beginning of March 2012 at an initial rate of approximately 2,500 bopd.

Rancho Hermoso NRI production increased 49% and 79% from the third quarter of 2011 to 2012and the nine months ended March 31, 2011 to 2012, respectively, primarily due to the successful drilling of RH 11, RH 12, RH 13, and RH 14, which came on production in September 2011, October 2011, December 2011 and January 2012, respectively, at combined average rates of approximately 5,800 bopd.

The Corporation’s producing assets in Brazil were sold effective July 2011.

Crude Oil Sales

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Rancho Hermoso – tariff	**$ 14,151**	$ 8,677	63%	**$ 37,328**	$ 11,468	225%
Rancho Hermoso – NRI	**33,096**	21,947	51%	**98,185**	50,483	94%
	47,247	30,624	54%	**135,513**	61,951	119%
Other	**1,385**	1,505	(8%)	**3,690**	3,857	(4%)
Crude oil sales, net after royalties	**$ 48,632**	$ 32,129	51%	**$ 139,203**	$ 65,808	112%

Crude oil sales are recorded net after royalties. The increase in crude oil sales from the three and nine months ended March 31, 2011 compared to the same period in 2012 is primarily the result of increased overall sales of 27% and 132%, respectively. In the nine months ended March 31, 2012, the increase is offset by a decrease in overall realized prices resulting from tariff production contributing a greater portion to the production mix. In the three and nine months ended March 31, 2012, tariff sales represented 70% and 67% of total sales by volume, respectively, compared to 69% and 58% in the three and nine months ended March 31, 2011, respectively.

Average Benchmark and Realized Sales Prices

	Three months ended March 31,			Nine months ended March 31,		
$/bbl	**2012**	2011	Change	**2012**	2011	Change
Brent Crude (“Brent”)	**$ 118.64**	$ 105.87	12%	**$ 113.19**	$ 90.03	26%
West Texas Intermediate (“WTI”)	**$ 102.98**	$ 94.07	9%	**$ 95.43**	$ 85.00	12%
Rancho Hermoso – NRI	**$ 101.70**	$ 83.02	23%	**$ 93.60**	92.22	1%
Other	**73.03**	74.81	(2%)	**69.40**	66.06	5%
Total NRI	**100.12**	82.44	21%	**92.44**	89.70	3%
Rancho Hermoso – tariff	**17.36**	13.97	24%	**16.72**	13.92	20%
Average realized sales price	**$ 41.94**	$ 35.49	18%	**$ 41.74**	$ 46.04	(9%)

The Corporation’s Rancho Hermoso NRI sales prices increased 23% in the third quarter of2012 compared to the same period in2011 and 1% in the nine months ended March 31, 2012 compared to the same period in 2011. Overall NRI sales prices also increased 21% in the third quarter of 2012 to $100.12/bbl from $82.44/bbl in the comparable period and 3% increase in the nine months ended March 31, 2012 to $92.44/bbl from $89.70/bbl in the comparable period.

Tariff sales are based on contractual amounts. The increase in realized tariff sales is the result of an increase in the contractual amount the Corporation received for tariff sales in the third quarter of 2012 compared to the third quarter of2011, and the nine months ended March 31, 2012 compared to the nine months ended March 31, 2011. The Corporation expects realized tariff prices to be $17.36/bbl for the remainder of the contract period, which is until August 2018.

Royalties

In Colombia, royalties are taken in kind generally at a rate of 8% until net field production reaches 5,000 bopd, then increase on a sliding scale to 20% up to field production of 125,000 bopd. The Corporation’s average royalties on NRI production for the three and nine months ended March 31, 2012 were 9.4% and 9.1%, respectively, compared to 8.7% and 8.4%, respectively, for the three and nine months ended March 31, 2011. There are no royalties on tariff production.

Operating and Transportation Expenses

Total operating and transportation expenses were as follows:

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Operating expenses	**$ 11,917**	$ 7,390	61%	**$ 36,068**	$ 18,448	96%
Transportation expenses	**7,332**	2,961	148%	**20,023**	5,682	252%
Total operating and transportation expenses	**$ 19,249**	$ 10,351	86%	**$ 56,091**	$ 24,130	132%
$/bbl	**$ 16.60**	$ 11.43	45%	**$ 16.82**	$ 16.88	-

As described above, the Corporation's primary producing property is the Rancho Hermoso field in Colombia. Under its risk service contract with Ecopetrol, the Corporation receives a set tariff price per barrel of oil produced and sold from the Mirador formation. The Corporation incurs 100% of the operating expenses related to such production. Under its production sharing contract with Ecopetrol, the Corporation receives a net revenue interest in the production from the other formations at Rancho Hermoso and incurs 100% of the operating expenses related to such production. Since the total operating expenses incurred at Rancho Hermoso relate to 100% of the gross production from the field, the Corporation allocates operating expenses each quarter to tariff and NRI oil based on gross sales volumes. When stating NRI operating expenses on a per barrel basis, this results in a multiplier being applied of gross NRI sales divided by net NRI sales, after royalties. However, the gross operating expense per barrel to produce and sell a tariff barrel versus an NRI barrel remains the same.

An analysis of operating expenses is provided below:

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Rancho Hermoso						
Operating expenses	**$ 10,697**	$ 5,236	104%	**$ 32,552**	$ 14,350	127%
Gross sales (Mbbls)	**2,486**	1,718	45%	**6,748**	3,326	103%
$/bbl of gross sales	**$ 4.30**	$ 3.05	41%	**$ 4.82**	$ 4.31	12%
Allocated to:						
Rancho Hermoso – tariff	**$ 3,774**	$ 1,892	99%	**$ 11,063**	$ 3,091	258%
Rancho Hermoso – NRI	**6,923**	3,344	107%	**21,489**	11,259	91%
	10,697	5,236	104%	**32,552**	14,350	127%
Other	**1,220**	2,154	(43)	**3,516**	4,098	(14%)
Total operating expenses	**$ 11,917**	$ 7,390	61%	**$ 36,068**	$ 18,448	96%
$/bbl						
Rancho Hermoso – tariff	**$ 4.63**	$ 3.05	52%	**$ 4.95**	$ 3.75	32%
Rancho Hermoso – NRI	**$ 21.28**	$ 12.65	68%	**$ 20.49**	$ 20.57	-
Total operating expenses	**$ 10.28**	$ 8.16	26%	**$ 10.81**	$ 12.91	(16%)

Total operating expenses have increased 61% in the third quarter of 2012 compared to 2011, which relates to the increase in production volumes between the comparable periods of 32%. Similarly, operating expenses increased 96% from the nine months ended March 31, 2012 compared to the same period in 2011, also due to an increase in production volumes during the comparable period of 123%. As the production volume increases relate entirely to the Rancho Hermoso field, the Corporation has been able to realize operating efficiencies from the nine months ended March 31, 2011 to the nine months ended March 31, 2012. However, the Corporation did see increases in gross operating expenses per barrel of 41% from the third quarter of 2011 to 2012 and 12% from the nine months ended March 31, 2011 to the same period in 2012 mainly due to increases in diesel prices and consumption, which remain a very significant operating cost of the field. In addition, multiple incidents of electro-submersible pump failures occurred during the third quarter of 2012 as well as the failure of an injection pump, all of which resulted in a decrease in production and an increase in operating expenses during the period.

An analysis of transportation expenses is provided below:

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2011**	**2010**	Change
Rancho Hermoso – tariff	**$ 725**	$ 59	>1,000%	**$ 3,152**	$ 218	>1,000%
Rancho Hermoso – NRI	**5,990**	2,753	118%	**15,498**	4,819	222%
Other	**617**	149	313%	**1,373**	645	113%
Total transportation expenses	**$ 7,332**	$ 2,961	148%	**$ 20,023**	$ 5,682	252%
$/bbl						
Rancho Hermoso – tariff	**$ 0.89**	$ 0.09	889%	**$ 1.41**	$ 0.26	442%
Rancho Hermoso – NRI	**$ 18.41**	$ 10.41	77%	**$ 14.78**	$ 8.80	68%
Total transportation expenses	**$ 6.32**	$ 3.27	93%	**$ 6.00**	$ 3.97	51%

Transportation expenses have increased in both the three and nine months ended March 31, 2012 compared to the same periods in 2011 on a total and per barrel basis due to significantly increased sales volumes, higher trucking tariffs and increased average delivery distances.

Operating Netback

Total operating netback is heavily influenced by the sales volume split between tariff and NRI oil. Consequently, there could be a reduction in total operating netback, even though both tariff and NRI operating netbacks have improved because the Corporation receives a lower fixed price for its tariff sales. Readers are cautioned that a comparison of total operating netback for the Corporation from one period to another is not meaningful if the ratio of tariff oil sales to NRI oil sales has materially changed, as is the case from the nine months ended March 31, 2011 to March 31, 2012. A more meaningful analysis is to examine operating netback by major production category, which is provided after the table below.

	Three months ended March 31,			Nine months ended March 31,		
$/bbl	**2012**	2011	Change	**2012**	2011	Change
Crude oil sales, net of royalties	**$ 41.94**	$ 35.49	18%	**$ 41.74**	$ 46.04	(9%)
Operating and transportation expenses	**(16.60)**	(11.43)	45%	**(16.82)**	(16.88)	-
Operating netback (see note to reader above)	**$ 25.34**	$ 24.06	5%	**$ 24.92**	$ 29.16	(15%)

Operating netback by major production category was as follows:

	Three months ended March 31,			Nine months ended March 31,		
$/bbl	**2012**	2011	Change	**2012**	2011	Change
Rancho Hermoso – tariff oil						
Tariff revenue	**$ 17.36**	$ 13.97	24%	**$ 16.72**	$ 13.92	20%
Operating and transportation expenses	**(5.52)**	(3.14)	76%	**(6.36)**	(4.01)	59%
Operating netback	**$ 11.84**	$ 10.83	9%	**$ 10.36**	$ 9.91	5%
Rancho Hermoso – NRI oil						
Crude oil sales, net of royalties	**$ 101.70**	$ 83.02	23%	**$ 93.60**	$ 92.22	1%
Operating and transportation expenses	**(39.69)**	(23.06)	72%	**(35.27)**	(29.37)	20%
Operating netback	**$ 62.01**	$ 59.96	3%	**$ 58.33**	$ 62.85	(7%)

General and Administrative Expenses

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Gross costs	**$ 5,088**	$ 2,819	80%	**$ 15,529**	$ 10,929	42%
Less: capitalized amounts	**(1,480)**	-	n/a	**(4,691)**	-	n/a
General and administrative expenses	**$ 3,608**	$ 2,819	28%	**$ 10,838**	$ 10,929	(1%)
$/bbl	**$ 3.11**	$ 3.11	-	**$ 3.25**	$ 7.65	(58%)

Gross general and administrative expenses increased 80% in the third quarter of 2012 compared to 2011 primarily due to an increase in the number of staff to support operations in Colombia.

Net Finance Income and Expense

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Interest income on bank deposits	**$ (718)**	$ (196)	266%	**$ (1,922)**	$ (694)	177%
Fair value adjustment on equity tax payable	**(39)**	-	n/a	**(7)**	-	n/a
Accretion of decommissioning obligations	**382**	489	(22%)	**799**	1,566	(49%)
Interest expense	**378**	146	159%	**1,777**	2,850	(38%)
Net finance (income) expense	**$ 3**	$ 439	(99%)	**$ 647**	$ 3,722	(83%)

Interest – Interest expense decreased in the three and nine months ended March 31, 2012 compared to the same periods in 2011 due to a combination of lower convertible debenture debt levels and capitalization of borrowing costs.

Commodity contracts – The Corporation enters into derivative risk management contracts in order to ensure a certain level of cash flows to fund planned capital projects. At March 31, 2012, the Corporation had one financial WTI oil collar outstanding under the following terms:

Period	**Volume**	**Type**	**Price Range**
Dec 2011 – June 2012	1,000 bbls/day	Financial WTI Oil Collar	$85.00 – $108.50

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

	Three months ended March 31,		Nine months ended March 31,	
	2012	2011	**2012**	2011
Unrealized change in fair value	**$ (16)**	$ (2,401)	**$ 438**	$ (4,355)
Realized cash settlement	**(1)**	(323)	**(79)**	(323)
Total gain (loss)	**$ (17)**	$ (2,724)	**$ 359**	$ (4,678)

Stock-Based Compensation Expense

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Gross costs	**$ 3,079**	$ 3,236	(5%)	**$ 9,344**	$ 7,947	18%
Less: capitalized amounts	**(1,306)**	-	n/a	**(3,503)**	-	n/a
Stock-based compensation expense	**$ 1,773**	$ 3,236	(45%)	**$ 5,841**	$ 7,947	(27%)

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

Depletion, Depreciation and Amortization Expense

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Depletion, depreciation and amortization expense	**$ 18,088**	$ 8,477	113%	**$ 41,127**	$ 16,142	155%
$/bbl	**$ 15.60**	$ 9.36	67%	**$ 12.33**	$ 11.29	9%

Total depletion, depreciation and amortization costs have increased in the three and nine months ended March 31, 2012 as compared to the same periods in 2011 as a result of significantly increased production levels and significant development costs spent at Rancho Hermoso. Under IFRS, the Corporation depletes its assets on a component basis utilizing total proved plus probable reserves as opposed to depleting it assets using total proved reserves under Canadian GAAP.

Income Tax Expense

	Three months ended March 31,		Nine months ended March 31,	
	2012	2011	**2012**	2011
Current income tax expense	**$ 4,589**	$ 1,147	**$ 8,939**	$ 4,252
Deferred income tax expense (recovery)	**(7,569)**	125	**4,463**	(2,143)
Income taxes	**$ (2,980)**	$ 1,272	**$ 13,402**	$ 2,109

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 33%.

Cash and Funds from Operations and Net Income (Loss)

	Three months ended March 31,			Nine months ended March 31,		
	2012	2011	Change	**2012**	2011	Change
Cash provided by operating activities	**$ 19,662**	$ 1,686	> 1000%	**$ 82,593**	$ 19,571	322%
Funds from operations	**20,042**	13,518	48%	**59,320**	23,863	149%
Per share – basic ($)	**0.03**	0.03	-	**0.11**	0.05	120%
Per share – diluted ($)	**0.03**	0.03	-	**0.10**	0.05	100%
Net income (loss)	**3,663**	(852)	n/a	**14,726**	(45,837)	n/a
Per share – basic and diluted ($)	**0.01**	-	-	**0.03**	(0.10)	n/a

Capital Expenditures

	Three months ended March 31,		Nine months ended March 31,	
	2012	2011	**2012**	2011
Drilling and completions	**$ 12,895**	$ 5,375	**$ 53,158**	$ 25,050
Facilities and infrastructure	**26,621**	5,557	**57,454**	9,658
Seismic, capitalized general and administrative expenses, capitalized borrowing costs and other	**12,908**	9,733	**35,593**	16,601
Total capital expenditures	**$ 52,424**	$ 20,665	**$ 146,205**	$ 51,309
Recorded as:				
Expenditures on exploration and evaluation assets	**$ 7,473**	$ -	**$ 25,137**	$ -
Expenditures on property, plant and equipment	**$ 44,951**	$ 20,665	**$ 121,068**	$ 51,309

Capital expenditures in the third quarter of 2012 primarily relate to:

- RH 14, 15 and RH 17 drilling and completion costs at the Rancho Hermoso field;
- Participation in drilling and completion of R53H and R55H at the Capella field (non-operated);
- Participation in drilling of L17H and R56H at the Capella field (non-operated);
- Tardigrado-1 drilling costs on the Andaquies block;
- Cachalote completion costs on the Andaquies block;
- Costs related to the construction of the Rancho Hermoso gas plant facilities designed for the separation of gas liquids from production at the Rancho Hermoso field;
- Facilities expansion at the Rancho Hermoso field; and
- Acquisition of an additional 9% and 10% interest in the LLA 23 block and the Santa Isabel block, respectively, for a total consideration of $4.5 million paid in common shares of the Corporation.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

Based on the Corporation's financial position and liquidity at March 31, 2012, its projected future cash flows, and its available credit capacity, management expects to be able to fund its working capital and capital project needs, and meet its other obligations, including servicing interest on its convertible debentures and bank debt through the end of calendar 2012. At March 31, 2012, the Corporation had cash, cash equivalents, and restricted cash of $68.1 million and working capital of $43.7 million. The Corporation believes it is well positioned financially with significant available credit capacity, assets that are providing strong production growth and operating netbacks, along with an extensive inventory of exploration prospects. The Corporation's assets provide significant funds from operations and are its largest source of liquidity. The Corporation has a history of generating positive funds from operations.

Credit Facilities and Debt

The Corporation, through its wholly-owned subsidiary, Canacol Energy Colombia S.A. (the "Borrower"), entered into a credit agreement for up to $32.0 million to fund the construction of a gas liquids separation facility at its Rancho Hermoso field. As at March 31, 2012, $14.1 million was drawn on the credit facility to fund such construction costs under a predetermined schedule. The credit facility is repayable in ten equal principal payments plus interest due at the end of each three month period starting on September 1, 2012. The facility bears interest at LIBOR plus 2.50% and is unsecured.

The Borrower is subject to certain financial and operations covenants, including maintaining a Leverage Ratio of less than 2.25, an Interest Coverage Ratio of less than 1.25, both calculated with reference to the Borrower's trailing twelve-month EBITDA, and minimum non-tariff oil production, net after royalties, of 3,000 barrels of oil per day ("bopd") from the closing date to September 30, 2012, and 2,500 bopd thereafter.

At March 31, 2012, the Corporation had revolving lines of credit in place in Colombia with an aggregate borrowing base of $19.6 million (COP$ 38.1 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. At March 31, 2012, no amounts were drawn under the facilities.

At March 31, 2012, the Corporation had letters of credit outstanding totalling $9.9 million to guarantee work commitments on exploration blocks. The total of these letters of credit reduce the amounts available under the revolving lines of credit described above.

The Corporation has convertible debentures outstanding with a face value of $27.6 million (fair value – $27.6 million) that mature on July 15, 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$1.0526 per share.

Share Capital

At May 14, 2012, the Corporation had 623.6 million common shares, 3.3 million warrants, 55.3 million stock options, and 190,000 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 March 31, 2012:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt	4,236	9,880	-	14,116
Trade and other payables	51,646	-	-	51,646
Commodity contracts	138	-	-	138
Equity tax payable	1,231	2,461	-	3,692
Convertible debentures – principal	-	-	25,542	25,542
Convertible debentures – interest	2,078	4,158	1,039	7,275
Warrants	1,692	-	-	1,629
Exploration contracts (see below)	61,100	15,100	-	76,200
Incremental production contract (Ecuador)	12,500	48,700	29,800	91,000
Office leases	1,342	1,795	6,208	9,345
	135,963	82,094	62,589	280,646

Exploration Contracts

The Corporation has entered into a number of exploration contracts in Colombia, Brazil and Guyana which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding commitments at March 31, 2012 of $76.2 million and has issued $12.6 million in financial guarantees, $9.9 million of which are secured under the Corporation's credit facilities through letters of credit and the remainder is held in trust and recorded as restricted cash.

A summary of the Corporation's work program commitments is presented below.

Colombia

The Corporation has remaining net work program and farm-in commitments totalling approximately $66.2 million, of which $51.1 million are due within a year. These commitments are planned to be satisfied by means of seismic work and exploration drilling.

Basin	Commitment Date	Block	Net Acreage (000 acres)	Working Interest	Phase	Work Program Commitments
Upper Magdalena	February 17, 2014	COR-11	124	70% (1)	1	155 km of 2D seismic and 1 exploration well
Upper Magdalena	February 17, 2014	COR-39	67	70% (1)	1	90 km of 2D seismic and 2 exploration wells
Middle Magdalena	June 29, 2012(4)	Santa Isabel	91	100%	1&2	1 exploration well
Middle Magdalena	November 28, 2012(4)	VMM-2	30	40%(2)	1	1 exploration well
Middle Magdalena	June 30, 2012(4)	VMM-3	16	20% (3)	1	100 sq. km 3D seismic and 1 exploration well
Putumayo	February 6, 2014	Andaquies	41	36%	1	60 sq.km 3D seismic
Putumayo	February 28, 2010 (block under suspension)	Coati	25	40%	5	1 exploration well
Putumayo – Caguan	August 1, 2012	Sangretoro	385	100%	1	300 km of 2D seismic
Putumayo – Caguan	June 29, 2012	Cedrela	320	100%	1	250 km of 2D seismic
Putumayo – Caguan	July 29, 2012(4)	Portofino	103	40%	1&2	1 exploration well
Llanos Basin	September 13, 2012	LLA 23	82	80%	1&2	94 sq. km 3D seismic and 1 exploration well
Llanos Basin	September 14, 2012(4)	LLA 10	74	39%	1	1 exploration well
Llanos Basin	June 29, 2012(4)	Cano los Totumos	11	51%	1	50 sq. km of 3D seismic and 1 exploration well

(1) The Corporation completed a farm-out of the COR-11 and COR-39 blocks in September 2011 whereby the farmee has agreed to pay 60% of the phase 1 work program commitments on each block.

(2) Working interest decreased to 20% subsequent to March 31, 2012 as a result of the farm-out to ExxonMobil. Under the terms of the agreement, ExxonMobil will pay 100% of the exploration commitment costs, resulting in an expected reduction of the Corporation's exploration commitments by $3.6 million.

(3) Full carry on minimum work program commitment by partner.

(4) Application for extension has been submitted to the ANH pending approval.

Brazil

The Corporation has net work program commitments totalling approximately $5.0 million due within a year on block 170 in the Reconcavo basin. These commitments are planned to be satisfied by means of drilling an exploration well in 2012. The Corporation is in advanced negotiations with a potential partner to farm-out 50% of its 100% operated working interest in the REC-T-170 block, with the transaction anticipated to close prior to the end of the third quarter 2012.

Guyana

The Corporation has net work program commitments totalling approximately $5.0 million due within a year. These commitments are planned to be satisfied by means of drilling an exploration well in 2012. The Corporation plans to farm-out all or part of its working interest in the Takutu PPL in 2012 and is currently reviewing bids from interested parties.

The operator is currently in discussions with the Guyanese government who have agreed to extend Takutu PPL to the initial exploration phase ending May 2015. The operator has stated that it has no reason to believe that the extension will not receive final approval.

Ecuador

In February 2012, a company in which the Corporation has a non-operated 25% equity participation interest was awarded a 15 year incremental production contract by the national oil company of Ecuador ("Petroecuador" or "EPPE") for the Libertador and Atacapi mature fields in Northern Ecuador. The operator is required to spend a total of $334 million ($92.9 million, net to the Corporation) over the 15 year period of the contract. The Corporation's net share of such work program commitments during calendar 2012 is $10.2 million.

Gas Purchases and Gas Plant

In 2011, the Corporation was awarded a contract by Ecopetrol to purchase produced natural gas from the Rancho Hermoso field at a fixed price of $6.50/MMbtu, which includes the associated liquids – naphtha, propane and butane. The contract is effective on January 1, 2012 and is for a period of 5 years. The Corporation has initiated the construction of a gas liquids separation facility with the intention of processing the future natural gas production and selling the resulting liquids. The gas plant construction is underway and is expected to cost approximately $30.8 million in total with all ancillary projects. At March 31, 2012, the Corporation had spent $26.2 million towards the construction of the gas plant; the remaining amount is expected due within a year. The Corporation has funded the construction of the gas plant through its term loan of up to $32.0 million.

SUBSEQUENT EVENT

In April 2012, the Corporation entered into a farm-out agreement with ExxonMobil Exploration Colombia Limited ("ExxonMobil") for the exploration of the Corporation's non-operated VMM 2 E&P contract located in the Middle Magdalena basin of Colombia. Under the terms of the agreement, ExxonMobil will pay 100% of the costs of drilling and testing of up to three wells to test conventional and unconventional targets in the La Luna and Rosablanca formations, up to a cap of gross $15.0 million for each vertical well and $17.5 million for each horizontal well. ExxonMobil will also pay Canacol $2.2 million for back-costs related to the acquisition of 3D seismic on the block. In return, ExxonMobil shall earn 50% of the Corporation's 40% interest in the contract.

OUTLOOK

For calendar 2012, the Corporation's focus is threefold: 1) to achieve strong base production and cash flow growth from drilling and re-completion programs at its Rancho Hermoso field; 2) to access potential near-term light oil production and cash flow from the LLA 23 contract, which is located immediately north of and on trend with the Rancho Hermoso field; and 3) to execute on a large exploration program which targets heavy oil in the Putumayo-Caguan basin and light oil in the Putumayo and Middle Magdalena basins.

In December 2011, the Corporation set a $150.0 million capital program for calendar 2012 and average production guidance of 14,000 to 16,000 net bopd for the same period.

SUMMARY OF QUARTERLY RESULTS

	IFRS							Canadian GAAP
	2012			2011				2010
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial								
Crude oil sales	**34,481**	40,941	26,453	37,339	23,452	15,669	15,219	5,330
Tariff revenue	**14,151**	14,300	8,877	9,676	8,677	1,212	1,579	1,874
Total revenues	**48,632**	55,241	35,330	47,015	32,129	16,881	16,798	7,204
Funds from operations (1)	**20,042**	24,480	17,761	11,200	18,024	1,829	7,766	(1,443)
Per share – basic and diluted ($)	**0.03**	0.05	0.03	0.04	0.04	-	0.02	-
Net income (loss)	**3,663**	(2,423)	13,486	19,625	(852)	(14,918)	(30,068)	(11,048)
Per share – basic and diluted ($)	**0.01**	-	0.03	0.04	-	(0.03)	(0.07)	(0.02)
Capital expenditures	**52,424**	62,425	31,356	24,824	20,665	22,403	8,241	6,089
Operations								
Tariff oil production (bopd)	**8,917**	8,971	6,476	7,568	7,023	980	1,259	1,152
NRI oil production (bopd)	**4,246**	4,422	3,274	3,880	2,935	2,347	1,729	1,559
Total oil production (bopd)	**13,163**	13,393	9,750	11,448	9,958	3,327	2,988	2,711

(1) Non-IFRS measure – see "Non-IFRS Measures" section.

RISKS AND UNCERTAINTIES

There have been no significant changes in the three and nine months ended March 31, 2012 to the risks and uncertainties as identified in the MD&A for the year ended June 30, 2011.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's management made judgements, assumptions and estimates in the preparation of the interim 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 interim financial statements. The following discussion highlights significant changes to critical accounting policies and estimates from those disclosed in the Corporation's MD&A for the year ended June 30, 2011 as a result of the adoption of IFRS.

Exploration and evaluation assets – The decision regarding technical feasibility and commercial viability of exploration and evaluation assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material changes in the future.

Opening statement of financial position – On transition to IFRS, the Corporation's full cost pool under Canadian GAAP was allocated to IFRS areas based on estimated proved plus probable reserve volumes. The estimate of proved plus probable reserve volumes required a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction, nor do they represent costs historically spent.

Reserve estimates – Under IFRS, estimates of reserves at the area level, rather than the country cost centre level, can have a significant impact on profit or loss, as they are a key component in the calculation of DD&A. A downward revision in the estimate of reserve quantities could result in a higher DD&A charge to profit or loss. Furthermore, DD&A is calculated used proved plus probable reserve estimates.

Reserve estimates can have a significant impact on profit or loss and the carrying value of capital assets. The process of estimating reserves requires significant judgement based on available geological, geophysical, engineering, and economic data, projected rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to interpretation and uncertainty. Reserve estimates impact profit or loss through depletion expense and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on profit or loss and can impact the carrying amount of capital assets.

Creditors also use reserve estimates to assess the allowable borrowing base under secured credit facilities. Although the Corporation currently does not have any reserve-based debt facilities, changes to reserve estimates can result in borrowing base increases or decreases, which could impact the Corporation's ability to access such debt facilities.

Asset impairments – For impairment testing, the assessment of facts and circumstances is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or Cash Generating Units ("CGU") for impairment, as well as the assessment of potential impairment reversals, requires estimates of an asset's or CGU's recoverable amount. The estimate of a recoverable amount requires a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. These assumptions and estimates are subject to change as new information becomes available and changes in any of the assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs, could result in an impairment of an asset's or CGU's carrying value.

Deferred income taxes – The Corporation recognizes a deferred income tax liability based on estimates of temporary differences between the book and tax value of its assets, liabilities, and tax pool pools. An estimate is also used for both the timing and tax rate upon reversal of the temporary differences, and for any potential future disputes on tax filings. Actual differences and the timing of reversals may differ from estimates, impacting the deferred income tax balance and profit or loss.

Contingencies – In the normal course of operations, the Corporation has disputes with industry participants for which the Corporation currently cannot determine the ultimate result. The Corporation records costs as they are incurred or become determinable.

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. A detailed discussion of new accounting policies that may affect the Corporation is provided in the interim condensed consolidated financial statements for the three months ended September 30, 2011.

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. Subject to scope limitation described below, 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. 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 interim filing is recorded, processed, summarized and reported within the time periods specified in securities legislation.

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. With the assistance of expert advisors and other members of management, the Corporation's CEO and CFO have assessed (subject to the scope limitation described below) the design effectiveness of the Corporation's ICFR as at March 31, 2012, using the framework and criteria established in Internal Control – Integrated Framework ("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 of the Corporation's ICFR framework.

During the nine months ended March 31, 2012, 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.

Limitation on Scope of Design

In accordance section 3.3 (1)(b) of National Instrument 52-109, which allows an issuer to limit its design of DC&P and ICFR to exclude controls, policies and procedures of a business that the issuer acquired not more than 365 days prior to the end of the fiscal period, the controls, policies and procedures of Carrao Energy Ltd., a privately held entity which was acquired by the Corporation effective November 29, 2011, have been excluded from the control design assessments discussed above. The scope limitation is based on the time required to document and assess the DC&P and ICFR of Carrao in a manner consistent with the Corporation's other operations. The Corporation's management is currently in the process of integrating Carrao into the existing internal controls and procedures of Canacol.

Carrao constitutes 9% of net assets, 8% of total assets, nil% of net revenues, and nil% of income before income taxes of the consolidated financial statements amounts as at and for the nine months ended March 31, 2012.

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.