

Canacol Energy Ltd.



May 11, 2011

## CAUTIONARY NOTE

This Management's Discussion and Analysis ("MD&A") for Canacol Energy Ltd. ("Canacol" or the "Corporation") of the financial results and related data is reported in United States dollars, has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), and should be read in conjunction with the audited consolidated financial statements for the fiscal year ended June 30, 2010 and the respective notes thereto. Additional information relating to the Corporation is on SEDAR at [www.sedar.com](http://www.sedar.com).

*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 ability to access sufficient capital from internal and external sources. In particular to forward-looking comments in this MD&A readers are cautioned that there can be no assurance that: the Corporation will be able to attain sufficient capital and financing to fund its expected obligations; that the Corporation will be able to increase production in Brazil, Colombia, or Guyana and achieve expected variable cost efficiencies and an overall reduction of costs on a per barrel basis; that hydrocarbon based royalties assessed by the Brazilian and Colombian governments will remain consistent or that the Brazilian and Colombian 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, the 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; fluctuation 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 Canacol 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, Canacol 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 Canacol 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.*

Canacol is a public company listed on the Toronto Stock Exchange and trades under the symbol CNE. The Corporation also trades on the BVC Colombia under the symbol CNE.C.

Unless otherwise stated, all dollar amounts presented in this MD&A are in thousands of United States dollars (unaudited). All references to C\$ are to Canadian dollars, references to US\$ or \$ are United States (U.S.) dollars, references to BRL\$ are to Brazilian Real, and references to COP\$ are to Colombian Pesos.

### **HIGHLIGHTS FROM Q3-F2011**

- 10,187 barrels of oil per day average daily production, up from 3,423 in the previous quarter
- \$18.0 million of cash flow from operating activities, before changes in non-cash working capital, up from \$1.8 million in the previous quarter.
- In March 2011, the Corporation received formal approval from Agencia Nacional de Hidrocarburos (“ANH”) on three new Exploration and Production (“E&P”) contracts (Sangretoro, COR 11 and COR 39).
- The Corporation provides a December 31, 2010 update of its Rancho Hermoso reserves estimates. Net working interest proved plus probable (“2P”) oil reserves increased by 69% for the Rancho Hermoso oil field. Net 2P reserves increased to 2.219 million barrels of oil, with 2P reserves replacement at 276%. The before tax NPV10 increased 182% to \$144.2 million.
- On February 15, 2011, the Corporation closed a gross proceeds C\$57.6 million (net proceeds of C\$54.7 million) bought deal common share financing through issuance of 41,745,000 common shares at a price of C\$1.38.
- The Corporation funded a 0.5% participation in the new pipeline construction project, the Oleoducto Bicentenario de Colombia (the “OBC”) at a cost of approximately US\$5 million.
- The Corporation commenced construction to expand of the production facilities in the Rancho Hermoso Field.
- During the quarter the Corporation completed production testing of two development wells in the Rancho Hermoso field, Rancho Hermoso 8 (“RH8”) and Rancho Hermoso 10 (“RH10”).

The RH8 well encountered 93 feet (“ft”) of net pay within 4 different reservoir intervals, which include, from top to bottom, the Mirador, Los Cuervos-Barco, Guadalupe, and Ubaque. The Los Cuervos - Barco reservoir at RH 8 contains 15ft of net oil pay, and was perforated between 9,349 and 9,364 ft md. The well flowed at a final stable gross rate of 3,927 bbl/d (982 bbl/d net) of 35° API light gravity oil.

The RH10 well encountered 110 feet of oil pay in the C7, Mirador, Los Cuervos-Barco, Guadalupe and Ubaque reservoirs, and tested a final stable gross rate of 8,122 bbl/d (2,030 bbl/d net) in the Ubaque reservoir and 10,944 bbl/d (2,736 bbl/d net) in the Guadalupe reservoir. The Los Cuervos - Barco reservoir at RH 10 contains 19ft of net oil pay, and was perforated between 9,410 and 9,425 ft md. The Los Cuervos-Barco flowed at a final stable gross rate of 6,792 bbl/d (1,698 bbl/d net) of 34° API oil. The C7 reservoir at RH 10 contains 12 ft of net oil pay, and was perforated between 8,974 ft md. An electrical submersible pump (“ESP”) was installed and the C7 reservoir flowed at a gross rate of approximately 429 bbl/d of 34° API oil.

## **HIGHLIGHTS FROM SUBSEQUENT EVENTS (AFTER Q3-F2011)**

- On May 3, 2011, the Corporation completed listing on the Toronto Stock Exchange (“TSX”) Canacol shares continue to be listed under the symbol “CNE”. Debentures continue to be listed under the symbol “CNE.DB”.
- On April 25, 2011, the Corporation provided an update on the Apoteri K-2 exploration well in Guyana. The well reached target depth at 9,812 feet measured depth within the Apoteri Formation on April 20, 2011. Light oil and gas shows were encountered within the Apoteri Formation, but due to poor reservoir quality, no reservoir fluids were recovered during drill stem testing. The K-2 well was subsequently abandoned.
- Subsequent to March 31, 2011, 334,900 shares were issued on exercise of options, 5,327,500 shares were issued on exercise of warrants, 20,050 shares were issued to consultants for services.

## **COMPANY OVERVIEW AND BACKGROUND**

Canacol Energy Ltd. (“Canacol” or the “Corporation”) (TSX: CNE) and (Bolsa de Valores de Colombia: CNE.C) is a Canadian-based independent oil exploration company operating primarily in Colombia, Guyana and Brazil. The Corporation’s average worldwide net production for the month of April 2011 was approximately 11,550 barrels of oil per day (“bbl/d”), which consisted of 3,900 bbl/d net royalty production and 7,650 bbl/d of tariff production, up from an average of 10,187 bbl/d (3,164 bbl/d net royalty production and 7,023 bbl/d tariff production) for the three month ended March 31, 2011. The corporation’s current share of production from the Rancho Hermoso and Entrerrios fields as of May 8, 2011 was 12,027, comprised of 8,145 bbl/d of tariff production and 3,882 bbl/d net royalty production.

The Corporation revised its production guidance for calendar 2011 upwards, from the previously disclosed yearly average of 10,000 to 11,000 bbl/d, to a new target of 10,500 to 11,500 bbl/d based primarily on stronger than anticipated production performance from recently drilled wells at its operated Rancho Hermoso field in Colombia.

### **Colombia**

Canacol has interests in 8 exploration and production contracts in Colombia, and plans to spend US\$127 million on various exploration and development projects in its contract areas in calendar 2011. These projects include the drilling of up to 7 development wells at its operated Rancho Hermoso Field (2 wells already drilled during the first calendar quarter 2011, leaving up to 5 more), 28 appraisal and development wells at its heavy oil discovery at Capella, and 3 exploration wells on its heavy oil blocks adjacent to the Capella oil discovery. Capital programs also include the acquisition of 650 km of 2D seismic on its heavy oil blocks, the drilling of 1 exploration wells on COR 39, and shooting 240 km of 2D seismic on COR 11 and 39 during the calendar year 2011 and expansion of facilities at the Rancho Hermoso Field, and funding of the Corporation’s 0.5% working interest in the OBC pipeline project.

### **Llanos Basin**

The Corporation has operated interests in the Rancho Hermoso (100% working interest) and Entrerrios (60% working interest) producing fields in the Llanos Basin. Both contracts are operated under Production Sharing and Risked Service contracts with Ecopetrol, the state oil company of Colombia.

***Rancho Hermoso Production Contract (100% operated working interest) and Entrerrios Production Contract (60% operated working interest)***

The Corporation's current average share of production from the Rancho Hermoso and Entrerrios fields is approximately 10,100 *bbl/d*, comprised of 3,032 *bbl/d* net of government royalty, and 7,023 *bbl/d* of tariff production. A portion of the Corporation's net oil production currently is secured by commodity contracts (Refer to the Risk Section).

For the tariff oil production, the Corporation receives an operating tariff per gross produced barrel of oil from Ecopetrol. The average tariff price for calendar 2011 and 2012 is expected to be approximately \$15.04 and \$17.36, respectively, per gross barrel plus transportation reimbursement, and is insensitive to West Texas Intermediate oil price fluctuations.

The Corporation plans to continue drilling development wells at Rancho Hermoso. The Corporation plans to drill up to a 7 development wells at Rancho Hermoso in during the calendar year 2011. The RH 8 and RH 10 wells were completed in January and February 2011, and the Corporation plans to drill the remaining wells starting in late second calendar quarter 2011. In addition to new development wells, the Corporation plans to expand the fluid handling capacity of existing facilities in order to process additional production. The expanded facility, expected to be completed by June 2011, will have the capacity to handle 200,000 barrels of fluid per day.

***Putumayo - Caguan Basin***

The Corporation is one of the largest exploration landholders in the Putumayo - Caguan Basin of southern Colombia, with working interests in four exploration and production contracts, all of them awarded under the new terms as regulated by the Agencia Nacional de Hidrocarburos ("ANH").

***Ombu E&P Contract - Capella Oil Discovery Appraisal***

The Corporation, under a farm out agreement entered into in July 2008, earned a 10% working interest in the Capella conventional heavy oil discovery operated by Sinochem Corporation on the Ombu E&P contract, where the operator is continuing with its appraisal drilling.

Since its discovery in 2008 the Corporation has participated in the drilling of 14 wells to date, and the acquisition of 189 square kilometres of 3D seismic. During calendar 2011, the Corporation intends to spend US\$17 million net to fund its share of the drilling and completion of 28 new wells and the construction of production facilities, as the development of the field commences.

***Tamarin E&P contract (100% operated working interest)***

In August 2009, Canacol, through its subsidiary Canacol Energy Colombia S.A. ("formerly Rancho Hermoso S.A."), was awarded the Tamarin Exploration and Production Contract ("Tamarin E&P contract") by the ANH.

The Corporation has a 100% working interest in the block, which is approximately 27,487 hectares in size and is located approximately 25 km to the southwest of the Ombu contract. Based upon the available geophysical and geological data in this frontier area, the Corporation has determined that the fault trend present at its Capella discovery to the northeast continues onto the Tamarin contract, setting up the potential for another Capella type heavy oil prospect. Canacol now has a significant operated exploration position at 100% working interest immediately offsetting its Capella heavy oil discovery. Canacol acquired 60 km of 2D exploration seismic on the Tamarin contract in May 2010 in satisfaction of the Phase 1 work program commitments. The Corporation plans to drill 2 exploration wells on Tamarin commencing in the third calendar quarter of 2011.

*Cedrela Exploration and Production Contract (100% operated working interest)*

In May 2010, Canacol was awarded the Cedrela Exploration and Production Contract (“Cedrela”) by the ANH. Cedrela is located immediately south of the Tamarin E&P Contract.

The Corporation has a 100% working interest in the block, which is approximately 129,418 hectares in size and is located in the Caguan - Putumayo Basin of Colombia. Based upon the available geophysical and geological data in this frontier area, the Corporation has identified 2 large structures similar in character to Capella on the Cedrela block. The Corporation is currently completing 250 kilometres of 2D seismic on the block and expects to finish processing and interpreting this seismic data by early July 2011. The Corporation plans to drill the 2 wells in the Cedrela block.

*Sangretoro E&P Contract (100% operated working interest)*

In February 2011, the Corporation was awarded the Sangretoro Exploration and Production contract (“Sangretoro E&P Contract”). The Corporation has a 100% working interest in the block, which is approximately 155,934 Ha in size and is located in the Putumayo-Caguan Basin of southern Colombia, and includes some of the lands previously under the Pacarana TEA .

The Corporation plans to acquire 300 km of 2D exploration seismic on the contract in second calendar quarter of 2011, followed by exploration drilling in early 2012.

The Sangretoro E&P contract covering approximately one-third of Pacarana TEA and the remaining area of the Pacarana TEA was relinquished.

**Upper Magdalena Valley Basin**

*COR 11 and 39 E&P Contracts (100% operated working interest)*

In February, 2011, the Corporation was awarded the COR 11 and COR 39 Exploration and Production contracts (COR 11 and COR 39 E&P Contracts). The Corporation has a 100% working interest in the blocks, which are approximately 71,595 Ha and 38,488 Ha, in area respectively, and are located in a new core area in the Upper Magdalena Valley in close proximity to the Guando and Abanico producing oil fields.

The Corporation has mapped 7 prospects and leads on the two contracts, and is committed to spending US\$28 million during the first phase of the exploration work program, which has duration of 3 years from the date of formal award. The work program involves the acquisition of 245 km of 2D exploration seismic and the drilling of 3 exploration wells. The Corporation anticipates conducting exploratory work on these contracts in calendar 2011 utilizing funds from equity financing that closed on February 15, 2011, as many of the prospects are drill ready and do not require additional seismic control.

The company has engaged advisor to assist in the Farmout of up to 40% working interest in each of the E&P contracts. The process is anticipated to commence in early June 2011.

**Guyana E&P**

**Takutu PPL (65% non-operated working interest)**

In May 2008, the Corporation negotiated a farm-in to a 7,800 sq km exploration contract located in the Takutu Basin, onshore Guyana adjacent to the border with Brazil, awarded to Groundstar Resources Ltd. (“Groundstar”) in July 2005 for a four year period. The operator was successful in extending the term of the contract to July 2012 with a commitment to drill 2 wells by May 2011. Canacol has a 90% working interest in the contract, with Groundstar Resources Limited (“Groundstar”), the operator of the Petroleum Prospecting License (“PPL”), holding the remaining 10%. Sagres Energy Inc. has earned 25% working interest in the PPL from Canacol by paying for 30% of the cost to drill the K-2 exploration well.

The Corporation completed the drilling of the first well in Guyana, which reached a target depth of 9,812 feet measured depth within the Apoteri Formation on April 20, 2011. Light oil and gas shows were encountered within the Apoteri Formation, but due to poor reservoir quality, no reservoir fluids were recovered during drill stem testing. The K-2 well was subsequently abandoned.

The Corporation, along with its Joint Venture partners, are currently evaluating the results of the K2 exploration well and its impact on the remaining prospectivity of the block prior to making the decision of which of the remaining prospects to drill. The operator is currently in discussion with Guyanese government with respecting to drilling a second well.

Gaffney Cline and Associates attributed gross mean recoverable prospective resources of 171 million barrels (111 million barrels net) and 133 million barrels (86 million barrels net) to each prospect respectively in a December 2009 report compiled for the Corporation. Total net cost for the second exploration well is anticipated to be \$9.5 million.

### **Brazil E&P**

In January 2006, a predecessor corporation acquired by Canacol through merger in October 2008, entered into a Consortium and Joint Operating Agreement with W. Washington Empreendimentos E. Participações Ltda, which subsequently has changed its name to W. Washington Petroleo S.A. (“W. Washington”), for the creation and operation of a Brazilian domiciled joint venture entity (“Brazil Joint Venture”) to hold, explore, develop and produce hydrocarbons in Brazil. Canacol holds a 47.5% interest and W. Washington, the operator, holds a 52.5% interest in the Brazil Joint Venture.

Canacol has interests in 10 exploration and production blocks in Brazil, including a 47.5% non-operated working interest in 5 producing oil fields located onshore in the Reconcavo Basin of Brazil, and a working interest of 37.5% in the REC170 contract also located in the Reconcavo Basin.

The Corporation, as a qualified Type 2 operator in Brazil, plans to participate in the upcoming Round 11 Exploration Bidding Process.

### ***Reconcavo Basin***

#### ***Block 170 (37.5% non-operated working interest)***

The prospect contains three prospective stacked reservoir sandstones that management estimates may contain up to 6 million barrels of gross mean unrisks recoverable light oil resource. The preferred well location is situated updip from an old well that recovered light oil from one of three prospective intervals.

The Corporation is currently in the process of acquiring the operator’s interest and operatorship in the REC170 contract, which upon completion will give the Corporation a 75% operated working interest and operatorship in the contract. The Corporation plans to drill 1 exploration well on the block in forth calendar quarter of 2011. Total net cost for the exploration well is anticipated at US\$3 million, which assumes a 75% working interest in the contract.

#### ***Producing Assets (47.5 % non-operating working interest)***

On November 2010, the Corporation signed an agreement with an arm’s length third party to dispose of its interest in 5 non-core non-operated producing oil fields, subject to regulatory approval. This divestment allows the Corporation remove small interests to support its efforts to focus on building a meaningful exploration portfolio in Brazil going forward.

### **Canada and Ireland E&P**

Operations in Canada are considered to be non-core. The Corporation continues to hold minor interests in some non-producing properties and is seeking to dispose of its interest in these remaining

properties. The Corporation does not expect to receive any significant proceeds from the sale of the remaining interests and is not planning any operations activities for these Canadian interests.

Exploration in Ireland is considered to be non-core and high risk and includes oil and natural gas exploration and the potential for development of salt cavern gas storage. The Corporation is currently reviewing potential alternatives for its Ireland interests and currently has no planned activity in Ireland.

## FINANCIAL HIGHLIGHTS AND SUMMARY OF RESULTS

Unless otherwise stated, amounts presented in this MD&A are in thousands of United State dollars (\$) or US\$. All discussions under the financial highlights section relate to oil and gas exploration and production operations of the Corporation.

OPERATING RESULTS	For the three months ended March 31				For the nine months ended March 31					
	2011		2010		2011		2010			
	Colombia	Brazil (1)	Colombia	Brazil (1)	Colombia	Brazil (1)	Colombia	Brazil		
	Non-Tariff	Tariff			Non-Tariff	Tariff				
<b>Sales Volume</b>										
Crude oil and NGL (bbl/d)	3,161	-	132	211	126	2,211	-	124	318	114
Natural gas (mcf/d)	-	-	-	-	-	-	-	-	-	-
Total (boe per day)	3,161	-	132	211	126	2,211	-	124	318	114
Total tariff sales (bbl/d)	-	6,899	-	1,562	-	-	3,006	-	1,511	-
<b>Production</b>										
Crude oil and NGLs (bbl/d)	3,032	-	132	732	126	2,297	-	124	456	114
Natural gas (mcf/d)	-	-	-	-	-	-	-	-	-	-
Total (boe per day)	3,032	-	132	732	126	2,297	-	124	456	114
Total tariff production (bbl/d)	-	7,023	-	1,549	-	-	3,092	-	1,525	-
<b>Average sale prices</b>										
Crude oil (\$/bbl) <sup>(5)</sup>	87.50	-	106.06	62.39	69.65	80.96	-	96.04	63.80	67.71
Oil equivalent (\$/boe)	-	-	-	-	-	-	-	-	-	-
<b>Operating netback (US\$/boe)</b>										
Commodity sales revenue <sup>(2)</sup>	87.50	-	106.06	62.39	69.65	80.96	-	96.04	63.80	67.71
Tariff revenue	-	13.89	-	11.53	-	-	13.66	-	13.36	-
Tariff transportation reimbursement	-	0.08	-	4.95	-	-	0.27	-	1.06	-
Non-refundable sales taxes	-	-	(4.19)	-	(6.77)	-	-	(3.85)	-	(3.89)
Royalties <sup>(5)</sup>	(7.00)	-	(6.89)	(5.00)	(5.74)	(6.48)	-	(6.11)	(5.10)	(5.83)
Transportation & processing <sup>(3)</sup>	(9.40)	(0.18)	(14.98)	(4.02)	(14.35)	(8.94)	(0.47)	(14.84)	(3.16)	(13.41)
Well workover & repair	-	-	-	(0.03)	(2.93)	(0.18)	(0.22)	-	(0.69)	(2.39)
MEP work unit provision	-	-	-	-	(3.72)	-	-	-	-	(3.02)
Operating expenses <sup>(4) (6)</sup>	(13.45)	(2.09)	(32.81)	(5.90)	(27.94)	(19.69)	(3.13)	(33.69)	(11.61)	(27.05)
<b>Netback <sup>(5)</sup></b>	<b>57.65</b>	<b>11.70</b>	<b>47.19</b>	<b>47.44</b>	<b>8.20</b>	<b>45.67</b>	<b>10.11</b>	<b>37.55</b>	<b>43.24</b>	<b>12.12</b>

<sup>(1)</sup> Brazil results were estimated based on Agencia Nacional do Petroleo "ANP" data.

<sup>(2)</sup> Colombian commodity sales revenue and tariff revenue include transportation revenue.

<sup>(3)</sup> Colombian transportation and processing charges relate to both tariff and non-tariff production.

<sup>(4)</sup> Colombian operating expenses relate to both tariff and non-tariff oil production volumes.

<sup>(5)</sup> "Netback" per boe is calculated as revenues net of sales taxes and royalties, less transportation & processing charges, well workover and repair and operating expenses and then divided by bbls sold. Netbacks do not have a standard meaning prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Management feels this is a useful metric as it is a common metric used by other companies operating in the oil and gas industry in order to provide a comparison of relative overall performance between companies. Management uses the metric to assess the Corporation's overall performance relative to that of its competitors and for internal planning purposes. In Colombia, the total sales volumes for the three months ended March 31, 2011 were 284,460 bbls (non-tariff) and 620,869 bbls (tariff).

<sup>(6)</sup> \$13.45 per bbl relates to the operating expenses per boe in Colombia of oil produced in this quarter. It does not take into account approximately \$1,600 relating to an opening inventory balance adjustment.

### Average Daily Crude Oil Production and Sales

Average oil production and sales increased during the three months ended March 31, 2011 compared to Q3-F2010, as a result of the Corporation's continued drilling success on the Rancho Hermoso field in Colombia. Actual sales may be different from production volumes due to crude oil in transit at the period end date.

FINANCIAL RESULTS	For the three months ended March 31,		For the nine months ended March 31,	
	2011	2010	2011	2010
<i>(US\$000s), except share data</i>				
<b>Petroleum and natural gas sales, net</b>				
Colombia <sup>(2)</sup>	22,321	3,722	51,416	7,932
Brazil <sup>(1)</sup>	1,131	1,270	2,924	2,402
	23,452	4,992	54,340	10,334
<b>Tariff revenue</b>	8,677	1,607	11,468	4,452
<b>Interest and other revenue</b>	196	165	694	1,059
<b>Total revenue</b>	32,325	6,764	66,502	15,845
<b>Cash from operating activities</b> <sup>(3)</sup>	18,024	(1,162)	27,204	(2,220)
Per share - basic and diluted	0.04	(0.00)	0.06	(0.01)
<b>Net loss</b>	(3,343)	(5,130)	(19,780)	(9,872)
Per share - basic and diluted	(0.01)	(0.02)	(0.04)	(0.04)
<b>Capital expenditures</b>				
Colombia <sup>(2)</sup>	15,820	2,042	41,412	11,530
Brazil <sup>(1)</sup>	187	1,623	912	2,175
Guyana	4,517	488	8,793	1,961
Canada	141	-	192	76
	20,665	4,153	51,309	15,742
<b>Total assets</b>	266,498	96,066	266,498	96,066
<b>Total long-term liabilities</b>	26,253	17,537	26,253	17,537
<b>Weighted average shares outstanding</b>				
Basic (000s)	471,056	332,288	442,606	271,705
Basic and Diluted (000s)	471,056	332,288	442,606	271,705

<sup>(1)</sup> Brazil results were estimated based on Agencia Nacional do Petroleo "ANP" data.

<sup>(2)</sup> Under the terms of one of Canacol's crude oil marketing agreement ("the Hocol agreement"), Canacol retains ownership of oil in transit until it reaches the export pipeline which can take several days at which point the ownership of the oil transfers from Canacol to Hocol. At March 31, 2011, there were approximately 42,000 bbls of oil in transit. These barrels have been included in the Corporation's production volumes. However, revenue of approximately \$3,825 and expenses of \$402 associated with these barrels will be reported in April when title transfer occurs.

<sup>(3)</sup> Cash flow from operating activities before changes in non-cash items.

Quarterly Information - Recurring Operations <i>(US\$000s, except production data and per share)</i>	F2011				F2010			F2009
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
<b>Petroleum and natural gas sales</b> <sup>(1) (3)</sup>								
Colombia	22,321	14,735	14,360	4,486	3,722	2,063	2,147	1,926
Brazil	1,131	934	859	845	1,270	585	547	68
<b>Total production revenue</b>	<b>23,452</b>	<b>15,669</b>	<b>15,219</b>	<b>5,331</b>	<b>4,992</b>	<b>2,648</b>	<b>2,694</b>	<b>1,994</b>
<b>Tariff revenue</b> <sup>(2)</sup>	<b>8,677</b>	<b>1,212</b>	<b>1,579</b>	<b>1,874</b>	<b>1,607</b>	<b>1,611</b>	<b>1,234</b>	<b>858</b>
Interest and other	196	247	251	212	165	265	629	425
<b>Total operating revenue</b>	<b>32,325</b>	<b>17,128</b>	<b>17,049</b>	<b>7,417</b>	<b>6,764</b>	<b>4,524</b>	<b>4,557</b>	<b>3,277</b>
<b>Total production (bbl)</b>	<b>284,757</b>	<b>212,549</b>	<b>166,230</b>	<b>141,905</b>	<b>77,219</b>	<b>38,519</b>	<b>40,427</b>	<b>37,855</b>
<b>Total tariff production (bbl)</b>	<b>632,084</b>	<b>102,427</b>	<b>112,788</b>	<b>104,839</b>	<b>139,370</b>	<b>151,907</b>	<b>126,673</b>	<b>92,367</b>
<b>Cash from (used in) operating activities</b> <sup>(4)</sup>	<b>18,024</b>	<b>1,829</b>	<b>7,351</b>	<b>(1,497)</b>	<b>(1,162)</b>	<b>(132)</b>	<b>(926)</b>	<b>(3,584)</b>
Per share	0.04	0.03	0.00	0.01	(0.02)	0.01	(0.00)	(0.02)
<b>Net (loss) gain</b>	<b>(3,343)</b>	<b>(13,835)</b>	<b>(2,602)</b>	<b>(11,648)</b>	<b>(5,130)</b>	<b>(4,157)</b>	<b>(585)</b>	<b>(4,500)</b>
Per share	(0.01)	(0.03)	(0.01)	(0.04)	(0.02)	(0.01)	(0.01)	(0.03)
<b>Total assets</b>	<b>266,498</b>	<b>185,635</b>	<b>179,149</b>	<b>158,762</b>	<b>96,066</b>	<b>102,728</b>	<b>80,633</b>	<b>73,299</b>
<b>Total long term liabilities</b>	<b>26,253</b>	<b>26,651</b>	<b>33,314</b>	<b>11,908</b>	<b>17,537</b>	<b>21,573</b>	<b>23,413</b>	<b>23,191</b>

<sup>(1)</sup> Under the terms of one of Canacol's crude oil marketing agreement ("the Hocol agreement"), Canacol retains ownership of oil in transit until it reaches the export pipeline which can take several days at which point the ownership of the oil transfers from Canacol to Hocol. At the end of March 31, 2011, 42,000 bbls of oil were in transit which were included as inventory and the respective revenues and expenses were recognized after March 31, 2011.

<sup>(2)</sup> Includes tariff revenue of \$13.86 per bbl during the quarter ended March 31, 2011.

<sup>(3)</sup> The Corporation had natural gas sales of approximately \$186 and \$521 during the three and nine months ended March 31, 2011, respectively.

<sup>(4)</sup> Cash flow from operating activities before changes in non-cash items.

## Petroleum and Natural Gas Sales (Net of Royalties)

The Corporation has three types of sales agreements in Colombia:

- Tariff (Rancho Hermoso Field - Mirador formation) - a risk service contract with Ecopetrol where the Corporation receives a fix tariff price per barrel plus reimbursement of transportation charges;
- Production revenue (Rancho Hermoso and Entrerrios Field - all other formations) - a risk participation contract where the Corporation is entitled to approximately 25% of production after Ecopetrol's share and ANH royalties. Ecopetrol's share and ANH royalties are taken in kind; and
- Production revenue (Capella Field) - based on WTI less ANH royalties. The royalties are taken in kind (Refer to Royalties table on page 12).

Operating revenue for the three months ended March 31, 2011 totalled \$32,325 (Q3-F2010 - \$6,764), representing an increase of \$25,561 or 377% compared to Q3-F2010. Operating revenue for the nine months ended March 31, 2011 was \$66,502 (The nine months ended March 31, 2010 - \$15,845) representing an increase of \$50,657 or 320% compared to nine months ending March 31, 2010.

Operating revenue consists of production revenue (non-tariff production), tariff production and interest and other revenue. The production revenue during Q3-F2011 totalled \$23,452 (Q3-F2010 - \$4,992) representing an increase of \$18,460 or 370% compared to Q3-F2010. For the nine months ended March 31, 2011, production revenue was \$54,340 (Nine months ended March 31, 2010 - \$10,334) representing an increase of \$44,006 or 426% compared to nine months ending March 31, 2010. Tariff revenue during Q3-F2011 totalled \$8,677 (Q3-F2010 - \$1,607) representing an increase of \$7,070 or 440% compared to Q3-F2010. For the nine months ended March 31, 2011 tariff revenue was \$11,468 (Nine months ended March 31, 2010 - \$4,452) representing an increase of \$7,016 or 157% compared to

nine months periods ending March 31, 2010. For the three and nine months periods Interest and Other Income are discussed below.

The increase in operating revenue for Q3-F2011 compared to Q3-F2010 is due to higher production volumes achieved by the Corporation and a higher pricing environment.

In Colombia, sales volumes of crude oil achieved during the three months ended March 31, 2011 totalled 284,460 bbls (3,161 bbl/d) (Q3-F2010 - 19,000 bbls (211 bbl/d)). Sales volumes for the nine months ended March 31, 2011 totalled 605,810 bbls (2,211 bbl/d) (Nine months ended March 31, 2010 totalled 87,200 bbls (318 bbl/d)). The average price achieved in Colombia in Q3-F2011 was \$87.50/bbl compared to \$62.39/bbl in Q3-F2010.

In Colombia, tariff sales volumes during Q3-F2011 totalled 620,869 bbls (6,899 bbl/d) (Q3-F2010 - 140,571 bbls (1,562 bbl/d)). For the nine months ended March 31, 2011, tariff sales totalled 823,586 bbls (3,006 bbl/d) (Nine months ended March 31, 2010 - 412,697 (1,511 bbl/d)). The average tariff price for Q3-F2011 was \$13.97/bbl; Q3-F2010 was \$16.48/bbl including transportation reimbursement of \$0.08 and \$4.95, respectively. The decrease in the transportation reimbursement is due to Ecopetrol picking up own oil during in 2011.

The increase in sales volume for Q3-F2011 compared to Q3-F2010 was due to the start up of RH-6, RH-7, RH-9, and RH-10.

Brazil sales volumes during Q3-F2011 totalled 11,917 bbls of light oil (132 bbl/d); (Q3-F2010 - 11,335 bbls (126 bbl/d)). For the nine months ended March 31, 2011, Brazil sales were 34,061 bbl (124 bbl/d) (Nine months ended March 31, 2010 - 31,131 bbls (114 bbl/d)). The average price achieved per bbl in Brazil in the Q3-F2011 was \$106.06/bbl (Q3-F2010 - \$69.65/bbl) including transportation reimbursement.

Sales Volumes (bbls)	For the three months ended		For the nine months ended	
	March 31		March 31	
	2011	2010	2011	2010
Colombia <sup>(1)</sup>	284,460	19,000	605,810	87,200
Brazil	11,917	11,335	34,061	31,131
<b>Total net sales</b>	<b>296,377</b>	<b>30,335</b>	<b>639,871</b>	<b>118,331</b>
Tariff sales	620,869	140,571	823,586	412,697
<b>Total</b>	<b>917,246</b>	<b>170,906</b>	<b>1,463,457</b>	<b>531,028</b>

Royalties as a percentage of gross petroleum and natural gas revenues by geographic region for the three and nine months ended March 31, 2011 and the prior period comparables are shown in the table below. The current base royalty regime in Brazil averages between 5% and 13% of gross production revenue. The actual rate the Corporation achieved for the three months ended March 31, 2011 in Brazil was 7.6% compared to 8.2% during Q3-F2010. In Brazil, royalty rates are based on a sliding scale on incremental production over and above certain production thresholds, calculated on a block by block basis. Therefore, if aggregate production on any one block increases above the contracted thresholds, the royalty on that block should decline over time. In Colombia, royalties are taken in kind and at a rate of approximately 8%. During Q3-F2011 Colombian royalties averaged 8%.

Royalties	Three months ended March 31,		Nine Months Ended March 31,	
	2011	2010	2011	2010
Colombia <sup>(1)</sup>	8.0%	8.0%	8.0%	8.0%
Brazil	7.6%	8.2%	7.6%	8.6%

<sup>(1)</sup> There are no royalties on the tariff production.

Brazil oil sales are subject to non-refundable sales taxes. This totalled \$50 during three months ended March 31, 2011 (Q3-F2010 - \$83). For the nine months ended March 31, 2011, non-refundable sales taxes were \$131 (Nine months ended March 31, 2010 - \$161). These have been recorded and netted against revenue for the three and nine months ended March 31, 2011.

#### Interest and Other Revenue

During the three months ended March 31, 2011 Interest and Other Revenue of \$196 (Q3-2010 - \$165) was recorded while for the nine months ended March 31, 2011 \$694 (Nine months ended March 31, 2010 - \$1,059). The increase in the Interest and Other Revenue compared to Q3-F2010 was due to increase in interest earned on cash investments.

#### Operating Expenses and Transportation Expenses- Petroleum and Natural Gas

For the three months ended March 31, 2011, operating expenses totalled \$10,351(Q3-F2010 - \$3,789). For the nine months ended March 31, 2011, operating expenses totalled \$24,130 (Nine months ended March 31, 2010 - \$10,045). Colombian operating expenses relate to both tariff and non-tariff oil production. The production expenses increased during the nine month period ended March 31, 2011 compared to the same period in 2010 as a result of higher costs for equipment rental facilities and increases in transportation costs due to higher production volumes and temporary increases in transport distances to deliver oil. Details by operating segment are outlined in the table below.

Operating Expenses (\$000s)	Three months ended March 31,		Nine months ended March 31,	
	2011	2010	2011	2010
<b>Operating expenses</b>				
Colombia <sup>(1)(2)</sup>	7,001	2,380	16,384	6,963
Brazil <sup>(2)</sup>	389	361	1,147	849
	<b>7,390</b>	<b>2,741</b>	<b>17,531</b>	<b>7,812</b>
Colombia transportation	2,782	817	5,801	1,716
Colombia well workover & repair	-	5	292	372
Brazil transportation	179	192	506	449
Brazil well workover & repair	-	34	-	85
MEP work unit provision	-	-	-	(389)
	<b>10,351</b>	<b>3,789</b>	<b>24,130</b>	<b>10,045</b>
<b>Operating expenses per boe</b>				
Colombia <sup>(2)</sup> Tariff	2.27	-	3.13	-
Non-Tariff <sup>(3)</sup>	13.45	5.90	19.69	11.61
Brazil <sup>(1)</sup>	32.81	27.94	33.69	27.05
Weighted Average	<b>5.99</b>	<b>12.51</b>	<b>10.72</b>	<b>12.46</b>
<b>Transportation expenses per boe</b>				
Colombia <sup>(2)</sup> Tariff	-	-	0.47	-
Non-Tariff	9.40	4.02	8.94	3.16
Brazil <sup>(1)</sup>	14.98	14.35	14.84	13.41
Weighted Average	<b>10.94</b>	<b>4.66</b>	<b>6.65</b>	<b>3.75</b>

<sup>(1)</sup> Colombian operating expenses relate to both tariff and non-tariff oil production volumes.

<sup>(2)</sup> Expenditures related to the planned non-routine enhancement workover program undertaken are presented separately and excluded from the calculation of ongoing operating costs. Transportation and processing charges and the MEP work unit provision are also shown separately.

<sup>(3)</sup> \$13.45 per bbl relates to the operating expenses per boe in Colombia of oil produced in this quarter. It does not take into account approximately \$1,600 relating to an opening inventory balance adjustment that is included in \$7,001 in total Colombian operating expenses showing above.

### Depletion, Depreciation, and Amortization (DD&A)

For the three months ended March 31, 2011, DD&A totalled \$10,652 (Q3-F2010 - \$3,701) while for the nine months ended March 31, 2011, overall DD&A expense was \$22,475 (Nine months ended March 31, 2010 - \$7,965). Depletion expense is calculated on a unit of production basis. The depletion rate for the Colombia operations was \$11.90 per barrel for the three months ended March 31, 2011 (Q3-F2010 - \$12.37). Depreciation expense is calculated on a straight-line basis. Accretion expense is calculated as a present-value calculation of the Corporation's Asset Retirement Obligation. The increase in the depletion expense is a result of higher production volumes achieved by the Corporation.

### General and Administrative

For the three months ended March 31, 2011, general and administrative (G&A) expenses were \$2,819 (Q3-F2010 - \$2,746) while for nine months ended March 31, 2011, overall G&A expense was \$10,929 (Nine months ended March 31, 2010 - \$6,292). The increase in the G&A is primarily due to increases in personnel costs and professional fees to support expanding operations. G&A expenses are incurred in Canada, Colombia and Brazil and primarily consist of management and advisory fees, professional fees, travel, and other administrative expenses needed to support the Corporation's growing operations.

### Interest and Financial Expense

For the three months ended March 31, 2011, Interest and Financial Expense was \$887 (Q3-F2010 - \$696). For the nine months ended March 31, 2011, Interest and Financial Expenses were \$3,592 (Nine

months ended March 31, 2010 - \$2,227). Interest and Financial Expense is comprised of interest on the Corporation's long-term debt facilities, lines of credit, and non-cash interest charges. Non-cash interest charges relate to the 12% convertible debentures and the accretion of the 8% and 12% convertible debentures. Non-cash interest charges for Q3-F2011 totalled \$1,040 (Q3- F2010 - \$301).

### **Foreign Exchange**

The Corporation's activities in Brazil use the Brazilian Real (BRL\$) and the Corporation's activities in Colombia use the Colombian Peso (COP\$) as the functional currency and therefore the Corporation is exposed to the risk of fluctuations in foreign exchange rates. The Corporation's sales contracts for oil produced in Brazil and Colombia are based on US dollar reference prices but are paid in Brazilian Real in Brazil and through a combination of US dollars and Colombian Pesos in Colombia. The Corporation's line of credit facilities are denominated in Colombian Pesos.

For the three months ended March 31, 2011, the Corporation incurred a net foreign exchange loss of \$1,918 (Q3-F2010 -\$78). For the nine months ended March 31, 2011, the Corporation incurred a net exchange gain of \$745 (Nine months ended March 31, 2010 - \$ 2,090). The foreign exchange loss for the three months ended March 31, 2011 is a result of the appreciation of the Canadian dollar relative to the US dollar, and the corresponding impact on the translation of the Brazilian operations from the Brazilian Real to U.S. Dollars.

The Corporation has entered into a foreign currency derivative contract to manage its exposure to the Colombian Peso. Refer to the Risk Factors Section below for additional details.

### **Commodity Contracts**

For the three months ended March 31, 2011, the Corporation had four commodity contracts in place. The WTI oil financial option collars have an expiry date in August through November 2011. The Corporation has not designated these derivatives as hedges and has therefore recorded the unrealized gain on the contract on the balance sheet with changes in its fair value recorded in the net earnings for the period. Refer to the Risk Factors section for specific details of the financial derivative contracts.

At March 31, 2011, the Corporation had a total net commodity contract liability of \$4,195 (June 30, 2010 - asset of \$227) relating to the oil financial option collars.

For the three months ended March 31, 2011, the Corporation had a net loss on commodity contracts of \$2,724 (Q3-F2010 - gain of \$82) on its oil collar. For the nine months ended March 31, 2011, the Corporation had a net loss on commodity contracts of \$4,678 (Nine months ended March 31, 2010 - \$148). The Corporation had a realized net loss on its commodity contracts during the three month period ended March 31, 2011 due to higher realized oil prices.

### **Stock Based Compensation**

For the three months ended March 31, 2011, a total of \$3,336 (Q3-F2010 - \$1,431) was expensed while for the nine months ended March 31, 2011, a total of \$8,247 was expensed (Nine months ended March 31, 2010 - \$2,369). The year-over-year increase can primarily be attributed to a combination of the relative timing of options granted during the quarter, the vesting of previously granted options, and the assessed value of the options issued.

### **Overlifting Volumes**

Included in overlifted volume payable is a provision, under a participation contract with Ecopetrol S.A., for repayment in barrels to Ecopetrol to replace volumes of crude oil sold for the Corporation's account due to the participant's pipeline transportation and storage constraints during the period. The market value of the liability of \$23,016, net of transportation reimbursement, has been estimated as at March 31, 2011, based on the overlifted volume of 281,518 barrels.

The unrealized loss on overlifting volumes of \$2,137 relates to overlifted payable existing at beginning of the period adjusted for the change in oil price at March 31, 2011.

### **Income Taxes**

Canacol is subject to taxation in Canada, Brazil, and Colombia. The Corporation's pre-tax income is subject to Colombian income tax at a statutory rate of 33%. The Corporation is also subject to Colombian presumptive and equity taxes, both of which are based on capitalization level in Colombia. The effective tax rates are lower than the statutory rates due to the results of the deductions for the acquisition of certain capital assets.

The current income tax expense for Q3-F2011 was an expense of \$1,147 (Q3-F2010 - expense of \$406), relating to Colombian income taxes. During nine months ended March 31, 2011, current income tax expense was \$4,252 (Nine months ended March 31, 2010 - \$1,251). Due to operating losses in Brazil and Canada, the Corporation was not subject to income taxes in these jurisdictions during the three and nine months ended March 31, 2011.

A future income tax asset is not recognized for the Corporation's Canadian net capital losses, non-capital loss, or other tax pool balances. Further, a future income tax asset has not been recognized on the Corporation's Brazilian tax losses or other tax pools. A valuation allowance for Canada and Brazil has conservatively been applied to the remainder of the future income tax assets in the entity due to uncertainty of realization.

As at March 31, 2011, the Company had a net deferred income tax liability of \$4,779. A majority of this balance relates to the book value in excess of the tax basis value on its petroleum and natural gas assets acquired through the acquisition of Canacol Energy Inc.

## ***CASH FLOWS FROM OPERATING, FINANCING, AND INVESTING ACTIVITIES - ONGOING OPERATIONS***

### **Operating**

For the three months period ending March 31, 2011, cash flow from operating activities before changes in non-cash working capital totalled an inflow of \$18,024 (Q3-F2010 - outflow of \$1,162) while for the nine months ended March 31, 2011, it totalled an inflow of \$27,204 (Nine months ended March 31, 2010 - outflow of \$2,220).

### **Financing**

For the three months ended March 31, 2011, the Corporation recorded net cash inflow from financing activities of \$56,137 (Q3-F2010 - outflow of \$291). For the nine months ended March 31, 2011, the Corporation recorded net cash inflow from financing operations of \$99,136 (Nine months ended March 31, 2010 - \$29,250). Cash inflow from financing activities for the three and nine months ended March 31, 2011 primarily relates to an equity financing that closed in February 2011 and the issuance of 8% convertible debentures.

### **Investing**

For the three months ended March 31, 2011, cash flows from investing activities totalled an outflow of \$21,072 (Q3-F2010 - \$7,437). For the nine months ended March 31, 2011, cash flow from investing activities totalled an outflow of \$69,005 (Nine months ended March 31, 2010 - \$8,981). For the three and nine months ended March 31, 2011, the Corporation incurred \$20,665 and \$51,309 in capital expenditures. A majority of the capital spent was related to the Corporation's Colombian and Guyana operations.

## LIQUIDITY AND CAPITAL RESOURCES

Management believes that a combination of cash on hand, plus the cash generated from operating activities plus funding through debt or equity financing or potential farm-outs will enable the Corporation to execute its planned drilling programs and exploration commitments in Colombia, Guyana and Brazil.

### Working Capital

Funding for the Corporation's expenditures during the three and nine months ended March 31, 2011 was provided by cash on hand, the issuance of 8% convertible debentures, equity financing and cash generated from operating activities. At March 31, 2011, the Corporation had positive working capital of \$97,816 (June 30, 2010 -\$34,315).

### Cash Flow From Operating Activities

The Corporation in the three and nine months ended March 31, 2011 generated cash flow from operations of \$6,188 and \$22,908, respectively, and anticipates positive quarterly cash flow going forward.

## COMMITMENTS, GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

### Minimum exploration program (Brazil)

As at March 31, 2011, the Corporation had minimum exploration program ("MEP") work unit commitments to complete negotiated exploration work on its onshore blocks awarded by the Agência Nacional do Petróleo, Gás Natural e Biocombustível ("ANP"), Brazil's National Petroleum Agency. MEP work units are satisfied through completion of exploration wells, seismic programs, and other exploration survey methods all of which have prescribed work units for completion. Therefore, although actual dollars spent on projects do not directly correlate to reducing the MEP work units, the financial guarantees related to non-performance are shown in the table below. The commitment is reduced as work is performed.

Bid Round	Basin/Block	Commitment Date	Extension	Gross Remaining MEP		Net Remaining MEP		Net Financial
				Work Units	Gross Financial Guarantee	Work Units	Guarantee <sup>1</sup>	
					\$1,766			\$662
9	Recôncavo - Block 170 <sup>2</sup>	June 5, 2010 (special extension)		1,000	BRL \$3,000	375	BRL \$1,125	
9	Recôncavo - Block 169	March 12, 2011	December 2, 2011	600	\$1,059	120	BRL \$360	\$212

<sup>1</sup> Net financial guarantee based on currently Canacol's net working interest. Canacol is in the process of acquiring the operator's interest and operatorship in the REC-T-170 contract, which upon completion will give the Corporation a 75% operated working interest and an operatorship contract.

<sup>2</sup> ANP has granted a special extension to the Corporation on the agreement BT-REC-60, Block-T-170. Block 170 expires six months after permitting approval is received from the landowner to access the land.

The round 9 (Reconcavo Basin) commitments are planned to be satisfied through a combination of the execution of an exploration drilling program and through financial settlement of MEP work units.

### Work program commitments (Colombia)

#### Round 10

The Corporation has secured two Exploration and Production Contracts ("E&P Contracts") in the Upper Magdalena Basin of Colombia via its wholly owned subsidiary Canacol Energy Colombia S.A.. Canacol has 100% operated working interest in each of COR-11 and COR 39 E&P contracts which were awarded by the ANH. Each of the two blocks has a six year exploration term divided into two 36 month exploration phases. The phase 1 work program commitments associated with each of blocks are summarized below:

Bid Round	Basin	Commitment Date	Block	Working Interest	Work program commitments	Financial Guarantee <sup>1</sup>
10	Upper Magdalena Basin	July 1, 2013	COR-11	100%	155 kms of 2D seismic and 1 exploration well	\$ 12,200
10	Upper Magdalena Basin	July 1, 2013	COR-39	100%	90 kms of 2D seismic and 2 exploration wells	\$ 15,600

<sup>1</sup> The Corporation will place a total of \$13.3M in letters of credit with ANH.

The Corporation signed three new E&P contracts with the ANH in February 2011 (Sangretoro, COR 11 and COR 39). The Sangretoro E&P contract is located in the Putumayo - Caguan Basin of southern Colombia, and was previously part of the Pacarana Technical Evaluation Area (“TEA”) that was awarded in 2009 to the Corporation. The Phase 1 commitment associated with the Sangretoro block is summarized below:

Phase	Basin	Commitment Date	Working Interest	Work program commitments	Financial Guarantee <sup>1</sup>
1	Putumayo-Caguan Basin	August 31, 2012	100%	300 kms of 2D seismic	\$ 6,000

#### Cedrela E&P Contract

On May 2010, the Corporation was awarded the Cedrela Exploration and Production Contract (“Cedrela E&P Contract”) by the ANH of Colombia. The Cedrela E&P contract is located in the Putumayo-Caguan Basin, and is approximately 50 kilometres directly southwest of the Ombu E&P contract which contains Capella heavy oil discovery. The Corporation has a 100% working interest in the Cedrela E&P Contract, which is 129,418 hectares (319,799 acres) in size. The terms of the 6 year contract are as follows:

Phase	Basin	Commitment Date	Working Interest	Work program commitments	Financial Guarantee
1	Putumayo-Caguan Basin	December 31, 2011	100%	250 kms of 2D seismic	\$ 5,400
2	Putumayo-Caguan Basin	June 30, 2013	100%	Drill 1 exploration well	\$2,000
3	Putumayo-Caguan Basin	December 31, 2014	100%	60 kms of 3D seismic	\$3,000
4	Putumayo-Caguan Basin	June 30, 2016	100%	Drill 1 exploration well	\$2,000

Based upon results of the Phase 1 exploration activities, the Corporation has the option to proceed to the Phase 2 exploration period and associated activities or relinquish the contract. This option also applies phase 3 and 4.

#### Other Commitments

In Guyana, the Corporation has work program commitments totalling approximately \$8,500 due within a year or less.

In addition, the Corporation has commitments for leases and its office premises. As of March 31, 2011, the payments required in each of the next five calendar years on these lease are as follows:

<u>Leases</u>	<u>\$</u>
2011	395
2012	527
2013	527
2014	108
2015	92

The Corporation is currently disputing certain amounts claimed by a joint venture operator. As adequate supporting financial documents have not been provided by the operator, the Corporation continues to record revenues, expenses and any amounts receivable from or payable to the operator using the Corporation's best estimates as of and for the three and nine months ended March 31, 2011. Any adjustments required upon final settlement in the joint venture operation will be recorded in the period as amounts owing to or receivable from the operator are settled. As part of negotiation of the disposition of non-core, non-operated producing properties in Brazil, these issues will be resolved.

#### *Gemini Oil and Gas Funds*

The Corporation executed a series of agreements with Gemini Oil and Gas Fund II, L.P. ("Gemini"), a Jersey based oil and gas investment fund, on April 17, 2009, whereby Gemini agreed, subject to certain preconditions, to invest up to \$9 million, to fund portions of the Corporation's development and appraisal programs in Colombia.

In return, Gemini was entitled to royalties from 11% to 31% of the Corporation's interest in gross revenue after government royalty less field operating costs from the field up to either a 400% payout ratio or until 95% of the ultimate recoverable reserves as determined from time to time as underlying the Concession area have been produced, whichever is the sooner. The Corporation had no obligation to repay these funds if net revenue from the underlying properties defined in the transaction ceased.

In July 2010, Canacol used \$18,000 of the net proceeds from an 8% convertible debenture offering to acquire the royalties on its Rancho Hermoso, Entrerrios, and Capella oil fields in Colombia from Gemini. This transaction was effective as of June 30, 2010. The Corporation issued 4,421,260 common shares at a price of \$0.78 (C\$0.82) per common share in connection with the transaction. These common shares were issued on July 16, 2010.

## **PENDING LAND AUCTION AWARD TRANSACTIONS**

### **Round 8 Land Auction**

The Corporation qualified for and bid for onshore land blocks offered by the ANP, Brazil's National Petroleum Agency in Brazil's Round 8 land auction held on November 28th and 29th, 2006 ("Round 8 Bid"). Canacol and its partners in the Round 8 Bid, W. Washington and Brownstone, were successful in winning and being awarded five separate blocks, each block totalling 180 square kilometres of exploration lands ("Round 8 Bid Lands") in the Tucano Basin which lies directly west of the Recôncavo Basin. However, the Round 8 Bid is the subject of a court injunction filed in Brasilia against the ANP. The premise for the injunction is that the restriction for any one E&P company to purchase more than four blocks of land in any one area, in any given bid round of land is not constitutional. As of this report date, the court injunction has been lifted in the superior court from one of two jurisdictions. Canacol and its partners in the Round 8 Bid have no information indicating that their successful Round 8 Bid Lands will not be retained by them.

No capital commitments are currently included in Canacol's capital budget for the round 8 lands.

## ***SUBSEQUENT EVENTS***

Discussed in relevant sections in this MD&A.

## ***OUTLOOK***

Canacol's goal is to build a significant oil production and exploration company in Latin America. The Corporation has established a production platform in its core operating areas in Colombia, along with large onshore appraisal and exploration positions in Colombia, Brazil, and Guyana. The Corporation is using its strong technical management team to realize the full production and reserves potential of its producing assets. In Colombia, the Corporation has identified a number of low risk opportunities within its operated fields that it intends to pursue, which are expected to result in significant increases in existing production and reserves. With current production levels increasing faster than planned due to better than anticipated performance from the recently drilled wells at Rancho Hermoso, the Corporation revised its guidance upward from previously disclosed average of 10,000 to 11,000 bbl/d to a new target of 10,500 to 11,500 bbl/d for calendar 2011.

The Corporation has announced a \$141 million capital budget in 2011 for exploration and development activities in Colombia, Guyana and Brazil. The budget includes the drilling 41 gross wells (13 net wells), which include 7 exploration wells and 34 appraisal and development wells and shooting 900km of 2D seismic. In addition, the Corporation plans to acquire 650 kilometres of 2D exploration seismic, the building of an early facility at the Capella discovery, the continued expansion of its operated Rancho Hermoso production facilities, and funding the Corporation's share of the OBC pipeline project in Colombia.

On the exploration side, the Corporation has met with success in its non-operated Ombu E&P contract in Colombia, with the discovery of the Capella oil field. This significant discovery, currently being appraised, will yield near term production and reserves gains, and represents a long term development project with large heavy oil reserves upside. The Capella reserves increased by 100% from F2009 to F2010 in net after royalty proven and probable reserves from 2.1 to 4.2 million net barrels and resulted in a 227% increase in net associated NPV10 to \$64.7 million. The Corporation's proven, probable and possible net reserves after royalty increased by 279% from 3.6 to 9.9 million net barrels, with net associated NPV10 increasing 644% to \$182 million.

The Corporation has also met with success in its Rancho Hermoso oil field in Colombia. Net 2P reserves increased by 69% to 2,219 million barrels of oil in December 2010, with a corresponding 2P reserves replacement ratio of 276%. Before-tax NPV10 increased 182% from \$51.2 million in June 2010 to \$144.2 million in December, 2010.

The Corporation has acquired the Tamarin, Cedrela, and Sangretoro contracts adjacent to the Capella oil field and two additional blocks in the bid Round 10 in Colombia (COR 11 and COR 39). The Corporation has also completed a seismic program on the Tamarin E&P contract, and is completing 2D seismic acquisition on Cedrela E&P contract.

The Corporation plans to drill a total 5 wells on its 3 exploration contracts in the Caguan (Sangretoro, Cedrela, and Tamarin) starting in the third calendar quarter of 2011. Canacol plans to acquire 250 km of 2D seismic and drill 1 exploration well on the COR 39 block in 2011.

In Guyana, the Corporation has a 65% working interest in a large onshore exploration block that contains an existing light oil discovery, Karanambo, and 2 large exploration prospects. The Corporation completed the drilling of the K-2 well. Light oil and gas shows were encountered within the Apoteri Formation, but due to poor reservoir quality, no reservoir fluids were recovered during drill stem testing. The K-2 well was subsequently abandoned, and the consortium is currently evaluating the next exploration drilling location on the block. The operator is currently in discussion with Guyanese government with respecting to drilling a second well.

## SHARES OUTSTANDING (as at May 11, 2011)

There are an unlimited number of no par value common shares authorized for issuance. Details of the issued and outstanding shares are as follows:

### Issued & Outstanding Share Capital

Number of shares issued and outstanding, March 31, 2011	499,099,660
Issued to consultants for services	20,050
Warrants exercised	5,327,500
Stock options exercised	334,900
Debentures converted	-
<hr/>	
Number of shares issued and outstanding, May 11, 2011	504,782,110

Subsequent to the three months ended March 31, 2011, 334,900 shares were issued on exercise of options, 5,327,500 shares were issued on exercise of warrants, 20,050 shares were issued to consultants for services.

## OPTIONS OUTSTANDING (as at May 11, 2011)

The following are the outstanding stock options issued by the Corporation and their respective exercise prices and expiry dates. At May 11, 2011, vested stock options totalling 13,870,671 options were exercisable at a weighted average exercise price of \$0.55 per common share and a total of 35,854,005 options were issued and outstanding at a weighted average exercise price of \$0.77.

### Stock Options Outstanding

	Number	Weighted Average Exercise Price	Expiry Date Range
Balance, March 31, 2011	34,184,005	\$0.77	
Option Grants			
Exercised	100,000	\$1.24	November 10, 2011
	50,000	\$0.67	February 28, 2013
	84,900	\$0.10	January 6, 2014
	33,334	\$0.10	March 4, 2014
	66,666	\$0.36	November 6, 2014
	<hr/>		
	334,900		
<hr/>			
Balance, May 11, 2011	33,849,105	\$0.77	

## WARRANTS OUTSTANDING (as at May 11, 2011)

Warrants Outstanding	Number	Weighted Average	
		Exercise Price	Expiry Date
Warrants Outstanding at March 31, 2011	5,667,500	\$0.18	May 14, 2011
	1,178,000	\$0.18	May 28, 2011
	6,845,500		
Exercised Warrants	5,077,500	\$0.18	May 14, 2011
	250,000	\$0.18	May 28, 2011
Warrants Outstanding at May 11, 2011	1,518,000	\$0.18	1 month

As part of the May 14 and 28, 2009 private placements, 24,000,000 warrants were issued. Each warrant entitled the holder to acquire one common share at a price of \$0.18 (C\$0.20) until May 14, 2011 (first closing) and May 28, 2011 (second closing). 19,232,000 of these warrants have been exercised as of May 11, 2011, leaving 1,518,000 outstanding as at May 11, 2011.

On July 23, 2009, the Corporation issued 1,109,524 warrants in connection with a private placement at an exercise price of \$0.28 (C\$0.30). In addition, the Corporation issued 1,500,000 warrants in connection with the sale of a promissory note receivable at an exercise price of \$0.28 (C\$0.30) for 18 months. All of these warrants have been exercised as of March 31, 2011.

## RISK FACTORS

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 Canacol's business plan.

As the Corporation has not experienced sufficient positive cash flow from operations to independently finance its growth and operations, it has been reliant on access to capital in the form of both debt and equity to fund on-going operations and to fund capital investments. Although periodic volatility of financial and capital markets may severely limit access to capital, the Corporation has been able to successfully attract the required investment capital.

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 (COP\$), the Brazil Real (BRL\$), and the Canadian dollar (C\$) as well as its debt balances which are denominated in US\$.

Much of the Corporation's revenue and exploration and development costs are expected to be received/paid in reference to US\$ denominated prices while a significant portion of its operating and general and administrative costs are denominated in Canadian dollars, the BRL\$, and the COP\$. As a result of ongoing adverse conditions, the Brazilian Real and the Colombian Peso have seen significant variation against the US\$ during 2010 and 2011 and it continues to have significant daily fluctuations

making this particular currency risk more acute. The Corporation has entered into a currency derivative in order to reduce its exposure to fluctuations between the US Dollar and the Colombian Peso of \$1.5 million per month, with the agreement expiring in May, 2011.

The Corporation, through its wholly owned subsidiary Canacol Energy Colombia S.A. has revolving operating lines of credit. These lines of credit bear interest at the Depósitos a Término Fijo (“DTF”) interest rate, a Colombian benchmark interest rate, plus spreads of 2% per annum on the balance outstanding resulting in an average rate of 5.5 % for the three and nine months ended March 31, 2011 (Three and Nine months ended March 31, 2010 - average of 9.9% and 10.5%, respectively).

In addition to the lines of credit discussed above, the Corporation, through its subsidiary Rancho Hermoso, also obtained three additional unsecured revolving lines of credit with an aggregate borrowing base of \$5,675 (COP\$ 10.6 billion). The lines of credit have similar interest rates as described above. The Corporation has not drawn down any amounts under these lines of credit.

Fluctuations in energy prices will not only impact revenues of the Corporation but may also affect lending policies of the Corporation’s lenders for existing and new borrowings. Crude oil prices are correlated with overall global economic growth and activity. The continuing volatility in the global economic environment has resulted in significant variation in crude oil prices over the last year. Any dramatic drop in crude oil prices will have a negative impact on the profitability of the Corporation which in turn will impact the operational cash flows of the Corporation as well as on its ability to finance capital expenditures. In absence of externally-sourced capital, this could limit growth prospects over the short run or may even require the Corporation to dispose of assets.

The Corporation entered into four oil price financial derivative collars with the following terms.

*WTI crude oil financial option collar:*

<b>Period</b>	<b>Volume</b>	<b>Type</b>	<b>Price Range</b>
Jan 2010 – Aug 2011	114 bbls/day	Financial WTI Oil Collar	US\$55.00 - US\$80.25
May 2010 – Aug 2011	500 bbls/day	Financial WTI Oil Collar	US\$70.00 - US\$100.45
Nov 2010 – Oct 2011	500 bbls/day	Financial WTI Oil Collar	US\$70.00 - US\$100.00
Dec 2010 – Nov 2011	500 bbls/day	Financial WTI Oil Collar	US\$70.00 - US\$100.00

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 contracts 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 is mitigated while balancing factors of economic dependence with profit maximizing. To date, the Corporation has not experienced any material credit loss in the collection of accounts receivable. All Brazilian oil sales made through the Joint Venture are to a single customer who is the government energy company (Petrobras), while in Colombia the majority of oil sales revenue and tariff oil revenue comes from three customers of which two are also government entities (Petrobras Colombia and Ecopetrol) and Hocol controlled by Ecopetrol. During the nine months ended March 31, 2011, the Corporation also entered into sales

agreements with Meta Petroleum Corp (“Meta Petroleum”), a subsidiary of Pacific Rubiales Energy; C.I. Gravinal S.A. (“Gravinal”); Comergroup S.A. (“Comergroup”) and Gasmocam S.A. (“Gasmocam”). Management continuously reviews its relationships with its customers to minimize any exposure risks.

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.

## **CRITICAL ACCOUNTING ESTIMATES**

Canacol’s significant accounting policies are contained in Note 2 to the audited consolidated financial statements for the year ended June 30, 2010.

### **Currency translation**

The accounts of the self-sustaining Canadian parent are translated using the current rate method, whereby assets and liabilities are translated at the period-end exchange rates and revenues and expenses are translated using average period exchange rates. Translation gains and losses relating to the self-sustaining operations are included as part of accumulated other comprehensive income. The Corporation continues to use the temporal method to translate the operations of its Brazilian subsidiaries as detailed in the Corporation’s annual consolidated financial statements.

### **Revenue recognition**

The Corporation receives tariff revenue under a risk service contract with Ecopetrol in which a tariff price per barrel of tariff oil production is paid to the Corporation. Ecopetrol is a Mixed Economy Company, with a commercial orientation, organized as an “Anonymous Society” (equivalent to a Corporation), under the Ministry of Mines and governed by the Social Statutes. Ecopetrol S.A. carries out hydrocarbon exploration, production, and transportation activities in Colombia both directly and through participation agreements with other companies operating in Colombia. The Corporation recognizes revenue based on production of tariff oil and collection is reasonably assured.

All contracts that Rancho Hermoso S.A. (“RHSA”) has signed with Ecopetrol are “risk contracts” because RHSA makes all investments and is in charge of producing at its own cost and risk. RHSA takes the risk regardless of the outcome. However, there are differences depending how the contract rewards RHSA. There are two cases:

In the case of production from the Mirador formation in the RHSA field, it is a service contract because all of the crude belongs to Ecopetrol and RHSA gets paid through a tariff per barrel. RHSA provides the service for oil production. This is referred to as a Risk Service Contract.

In the other cases (such as Ubaque in Rancho Hermoso and all formations in Entrerrios), the contract is a participation contract because RHSA is entitled to a proportion of the production. Therefore, RHSA gets paid its share of the oil production sold in the market. This is referred to as a Risk Participation Contract.

Exploration contracts refer to activities that the Corporation performs to determine the existence and location of hydrocarbons in the subsurface, including but not limited to geophysical and geochemical methods, and other operations to determine whether the discovery is a commercial field.

With regards to the Corporation’s accounting policies, certain policies are recognized as critical because in applying these policies management is required to make judgments, assumptions, and

estimates that have a significant impact on the financial results of the Corporation. The estimates used in applying these critical accounting policies are regularly reviewed and have been discussed with the Audit Committee. These policies include:

#### **Income taxes**

The Corporation uses the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are based on the differences between asset and liability balances reported for financial accounting purposes and those reported for income tax. Future income tax assets and liabilities are measured using the substantively enacted tax rates expected to apply in the years in which the temporary differences are expected to be recovered or settled. Future income tax assets are recognized to the extent that they are more likely than not to be realized.

#### **Property, plant, and equipment**

##### *Depletion and depreciation*

Petroleum and natural gas properties are recorded in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting for the oil and gas industry whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical costs, costs of drilling both productive and non-productive wells, production equipment, and overhead charges directly related to acquisition, exploration, and development activities. Gains or losses on disposal of properties are recognized only when crediting the proceeds to the recorded costs would result in a change of 20% or more in the depletion and depreciation rate.

##### *Ceiling test and unproved properties*

An impairment loss is recognized in net earnings when the carrying amount of a cost centre of petroleum and natural gas assets and properties is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is tested for recoverability by determining if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited by the amount by which the carrying amount exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties that are subject to a separate impairment test.

Certain costs related to unproved properties and major development projects are excluded from costs subject to depletion and depreciation until the earliest of a portion of the property becomes capable of production, development activity ceases, or impairment occurs. These properties are reviewed quarterly and are subject to a separate impairment test. Any impairment is transferred to the costs being depleted. If the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

#### **Asset retirement obligations**

The fair value of the estimated asset retirement obligations is recognized in the consolidated balance sheet in the period which the liability is identified and incurred and a reasonable estimate of the fair value can be made. The obligations recognized are the legal obligations of the Corporation to retire and perform site restoration on tangible long-lived assets such as well sites. The obligations are discounted to their present value using the Corporation's credit adjusted risk-free interest rate. The corresponding amount increases the carrying amount of the related asset. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense. The amounts capitalized to the related assets are amortized to earnings over the expected remaining life of the underlying resources using the unit of production method. Actual costs incurred upon settlement of the asset retirement obligations are charged against the obligation to the extent of the liability recorded.

#### **Stock based compensation plan**

The Corporation records compensation expense in the consolidated financial statements for stock options granted to employees, directors, and consultants using the fair value method. Fair values are

determined using the Black-Scholes option pricing model with compensation costs recognized over their vesting period. Any consideration paid to the Corporation on the exercise of stock options, along with amounts previously credited to Contributed Surplus, is credited to share capital.

#### **Financial instruments**

The Corporation's financial assets and liabilities consist of cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, convertible debentures, currency and commodity derivatives, and long-term debt. The fair value of these financial assets and liabilities approximates their carrying value, unless otherwise noted.

### ***IMPACT OF NEW AND PROPOSED ACCOUNTING STANDARDS***

#### ***Business combinations***

In January 2009, the Accounting Standards Board ("AcSB") issued Section 1582, Business Combinations, which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Corporation plans to adopt this standard July 1, 2011 and does not expect the adoption of this statement to have a material impact on its results of operations or financial position.

#### ***Consolidated financial statements and Non-controlling interests***

In January 2009, the AcSB issued Sections 1601, Consolidated Financial Statements, and 1602, Non-controlling Interests, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Corporation plans to adopt these standards effective July 1, 2011 and does not expect the adoption will have a material impact on its results of operations or financial position.

#### ***Goodwill and intangible assets***

In February 2008, the CICA issued Section 3064, "Goodwill and Intangible Assets", replacing Section 3062, "Goodwill and Other Intangible Assets" and Section 3450, "Research and Development Costs". Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company has adopted the new standards for its fiscal year beginning July 1, 2009. It establishes standards for the recognition, measurement, presentation, and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062.

#### ***International Financial Reporting Standards (IFRS)***

In April 2008, the CICA published the exposure draft "Adopting IFRSs in Canada". The exposure draft proposes to incorporate IFRS into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS.

The Corporations' June 30 fiscal year end requires IFRS financial statements for its fiscal year beginning on July 1, 2011.

Canacol expects the implementation of IFRS will have a moderate impact on Canacol's consolidated financial statements as the IFRS uses a conceptual framework similar to Canadian GAAP, but prescribes certain differences for recognition, measurement and disclosure principles.

Canacol commenced its IFRS conversion project in 2010 and has completed an initial scoping phase, and is establishing a project plan and project team, which includes key finance staff, management, and external advisors.

### **IFRS Conversion Project Plan**

The IFRS conversion project plan consists of three phases as identified below:

#### *Phase 1 - Initial Scoping (Completed)*

Canacol Management team have undertaken a preliminary high-level scoping study to consider the potential impact of the implementation of IFRS on the Corporation's financial reporting. The initial scoping includes the identification of key differences between Canadian GAAP and IFRS, and high-level changes required in accounting policies, systems and processes.

#### *Phase 2 - Detailed Assessment and Design (In progress)*

Comprehensive documentation and analysis of changes in accounting standards, policies, processes and procedures identified on scoping from Phase 1.

#### *Phase 3 - Implementation (In progress)*

Implementation and execution of changes identified from Phase 2.

### **Potential Impact of IFRS Adoption**

Significant differences that have been identified between Canadian GAAP and IFRS that will impact the Corporation's are:

- IFRS 1 - First -time adoption of IFRS;
- IAS 36 - Property, plant and equipment;
- IFRS 6 - Exploration and evaluation of mineral resources;
- IAS 36 - Impairment testing;
- IAS 37 - Provision, contingencies liabilities and contingencies assets (Decommissioning costs); and
- An increased level of disclosure requirements.

These differences have been identified based on the current IFRS standards issued and expected to be in effect on the date of transition. Certain IFRS standards may be modified, and as a result, the impact may be different than the Corporation's current expectations. Management is currently determining the financial statement impact of these standards. The impact on the consolidated financial statements is not reasonably determinable at this time.

#### *IFRS 1 - First Time Adoption of IFRS*

The transition to IFRS requires the Corporation to apply IFRS 1, which prescribes requirements for preparing IFRS compliant financial statements in the first reporting period after the changeover date (July 1, 2011). IFRS 1 includes a requirement for retrospective application of each IFRS as if they were always in effect. IFRS 1 also mandates certain exemptions for retrospective application and provides optional exemptions from retrospective application to ease the transition to IFRS in the transition year.

This standard will have a significant impact on Canacol's consolidated financial statements, at least from the perspective of reconciliation from Canadian GAAP to IFRS. However, this standard has the potential to be most complex to implement and have the greatest financial statement impact depending on policies choices made by Canacol.

### *IAS 36 - Property Plant and Equipment*

This standard may have a high impact at Canacol. The most significant impact would occur should Canacol choose to account for some of its properties, plant and equipment using the revaluation model as many of the Corporation's capital assets are expected to have fair value that are significantly different than historical costs.

IFRS and Canadian GAAP contain the same basic principles of accounting for property, plant and equipment; however, differences in application do exist, specifically for oil and gas companies. IAS 16 requires costs recognized as property plant and equipment to be allocated to the significant parts of the asset and to amortize each significant component separately. This is a departure from Canadian GAAP for full cost oil and gas companies, and may increase the number of components to amortize separately, and could impact the amount of amortization expense.

The Corporation is currently evaluating the impact of this accounting standard.

### *IFRS 6 - Exploration and Evaluation Expenditures*

The IFRS 6 provides specific guidance with respect to recognition, measurement, presentation and disclosure requirements for costs incurred in the exploration phase. Unlike Canadian GAAP, IFRS requires the identification and presentation of exploration and evaluation expenditures to be separated from developed and producing assets. In addition, Canacol will be required to perform an impairment test on exploration and evaluation expenditures when there is a determination that the expenditures have resulted in a technically feasible and commercially viable project. At that time, the expenditures would be tested for impairment, and then transferred to the developed and producing assets category.

Canacol expects to be significantly impacted by this standard due to the highly specific accounting policies. The Corporation is currently evaluating its policy options and applicable impact of these policies under IFRS.

### *Impairment of Assets ("IAS 36")*

IAS 36 uses the concept of cash generating units to accumulate asset carrying costs to test and measure impairment.

Under IFRS, the Corporation will no longer test for asset impairment at the cost center level (country level) as permitted under the Canadian GAAP full cost guideline. IFRS will require impairment testing to be performed at the cash generating unit level, which is lower than the current cost center level.

In addition, IAS 36 uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of: value-in-use and fair value less costs to sell. Value-in-use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP, which uses undiscounted cash flows as an initial first step to test impairment.

Under, under IAS 36, impairment losses that were previously recognized may be reversed where circumstances change such that the impairment is reduced. This differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

The Corporation is currently evaluating the impact of this accounting standard.

### *Decommissioning Costs ("IAS 37")*

Under IFRS, the recognition criteria for contingent liabilities are much more explicit than Canadian GAAP and may potentially require the booking of additional liabilities associated with the asset retirement obligations of Canacol's oil and gas assets. Liabilities for decommissioning and restoration

are recognized for both legal and constructive obligations. Under IFRS, the estimated liability is calculated at each reporting period using estimates of risk-adjusted future cash outflows, discounted using the risk free rate whereas under Canadian GAAP the estimated liability is estimated using a credit-adjusted rate, rather than a risk free rate.

Changes in the estimated timing of cash flows necessary to discharge the obligation are added to or deducted from the cost of the related asset and the adjusted amounts are amortized prospectively over the estimated useful life of the asset. The measurement of the present value of the estimate (arising due to different discount rates used) is likely to be higher under IFRS as compared to Canadian GAAP.

#### *Information Systems*

It is expected that the conversion to IFRS will have a minimal impact on the Canacol's information system. Canacol is implementing the map IFRS accounting and reporting requirements to changes required in the accounting system which will be implemented and tested during calendar 2011.

### ***MAINTENANCE OF DISCLOSURE CONTROLS AND PROCEDURES (DC&P) AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)***

Management and the Board of Directors are committed to the promotion of investor confidence by ensuring that trading in the Corporation's securities takes place in an efficient, competitive, and informed market. In accordance with the continuous disclosure requirements under the securities commission rules, TSX Venture Exchange policies and BVC policies, the Corporation has adopted a Corporate Disclosure Policy and has procedures in place to ensure that any sensitive information is identified, reviewed by management, and disclosed in a timely manner to the regulatory authorities, shareholders, and the public.

However, in contrast to the requirements under National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109), for the quarter ended March 31, 2011, the certifying officers have opted out under the rules afforded to TSX Venture issuers not to make any representations relating to the establishment and maintenance of disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as defined in NI 52-109.

Subsequent to the listing of the Company's stock on the Toronto Stock Exchange and the transition of the Company from a venture issuer status to a non-venture issuer, effective May 03, 2011, the Company has become subject to the full requirements of NI 52-109 as a non-venture issuer. Accordingly, commencing with the Company's first fiscal quarter (quarter ending September 30, 2011) following the quarter in which the Company became a non-venture issuer (quarter ended June 30, 2011), the certifying officers of the Company will be required to certify that they have designed and established DC&P and ICFR in accordance with an acceptable internal control framework. Furthermore, on an annual basis, effective June 30, 2012, the certifying officers of the Company will be required to certify that they have evaluated the effectiveness of the Company's DC&P and ICFR and have disclosed their conclusions about the effectiveness of such controls in the annual MD&A of the Company.

Under the provisions of NI 52-109, during the quarter that the venture issuers become a non-venture issuer, the certifying officers are not required to make any representations with respect to the design and maintenance of DC&P and ICFR. However, a Note to Reader must be provided (similar to Note to Reader provided by the venture issuers) to that effect in the basic certification issued for the quarter in which the Company becomes a non-venture issuer.

Management is in the process of documenting and assessing the design of its DC&P and ICFR in preparation for its full interim certification requirements as of September 30, 2011.

## **ADDITIONAL INFORMATION**

Additional information relating to the Corporation's regulatory filings can be found on SEDAR at [www.sedar.com](http://www.sedar.com).

# Corporate Information

## Management Team

Charle Gamba – President & Chief Executive Officer

Mark Holliday – Chief Operating Officer

Mark Teare – Vice President Exploration

Brian Hearst – Chief Financial Officer

Kevin Flick – Vice President of Capital Markets and Investor Relations

Luis Baena – Vice President of Business Development, Colombia

## Board of Directors

Michael Hibberd, Chairman

Luis Baena

Alvaro Barrera

Jason Bednar

Charle Gamba

Stuart Hensman

David Winter

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## Auditors

Deloitte & Touche LLP Calgary, Alberta

## Bankers

HSBC Bank Canada – Calgary, Canada

HSBC Bank Brasil - Rio de Janeiro, Brazil

Citibank, Bogota, Colombia

## Independent Reserve Engineers

DeGolyer and MacNaughton Canada Limited

## Legal Counsel

Davis LLP - Canada

Schmidt, Valois, Miranda, Ferreira & Agel – Brazil

Salazar Asociados Abogados - Colombia

## Stock Exchange Listings

Toronto Stock Exchange: CNE

BVC Colombia: CNE.C

Toronto Stock Exchange (Debentures): CNE.DB

## Transfer Agent & Registrar

Olympia Trust Company

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