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Management's Discussion and Analysis

Chinook Energy Inc. | 700, 700 - 2nd Street SW Calgary, Alberta T2P 2W1 TSX:CKE

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. ("our" or "we") for the three months ended March 31, 2013 and 2012 and should be read in conjunction with our condensed consolidated financial statements and accompanying notes as at and for the three months ended March 31, 2013 and 2012 and the consolidated financial statements and accompanying notes as at and for the years ended December 31, 2012 and 2011. This MD&A is based on information available as at May 14, 2013.

The terms "first quarter" and "current reporting period" or similar terms are used throughout this document and refer to the three months ended March 31, 2013. The term "same quarter of 2012" or similar terms are used throughout this document and refer to the three months ended March 31, 2012.

Additional Information

Additional information for Chinook, including our Annual Information Form for the year ended December 31, 2012 ("AIF") can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The condensed consolidated financial statements and comparative information for the three months ended March 31, 2013 and 2012 have been prepared by management in accordance with IAS 34 'Interim Financial Reporting' ("IAS 34") using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board. The consolidated financial position and results of operations include the accounts of our direct and indirect subsidiaries all of which are wholly owned. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per share amounts or as otherwise noted. Certain financial measures referred to in this MD&A, such as cash flow, cash flow per share, corporate netbacks, net debt, net production expense, cash G&A, etc., are not prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

Introduction to Chinook

We are a Calgary-based public oil and natural gas exploration and development company with predominately natural gas and liquids reserves in Western Canada and crude oil reserves onshore and offshore in Tunisia, North Africa. We are incorporated under the laws of the Province of Alberta, Canada. Our common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "CKE". Our head office and principal address is Suite 700, 700 – 2nd Street SW, Calgary, Alberta, Canada T2P 2W1.

Our continuing operating and reportable segments are as follows:

- **Canada** – includes our Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in the Peace River and Grande Prairie areas located along the northern portion of the border of the Provinces of British Columbia and Alberta.
- **Tunisia** – includes eight blocks totaling three million gross acres offshore in the Gulf of Hammamet within the Pelagian Basin (Cosmos, Yasmin and Hammamet Offshore) and the Sud Remada, Bir Ben Tartar, Jenein, Adam and Borj El Khadra Blocks, all onshore properties located within the Ghadames Basin.
- **Corporate** – includes derivative transactions and swap option gains and losses, general and administrative costs and assets held corporately.

Segmented financial information is presented after the elimination of intercompany transactions.

Forward-Looking Information

Statements throughout this report that are not historical facts may be considered "forward-looking statements". Investors should read the advisory under the heading "Forward-Looking Statements" in this MD&A.

Financial and Operating Highlights

Three months ended March 31	2013	2012
OPERATIONS		
Production		
Oil *(bbl/d)*	**3,565**	3,819
Natural gas liquids *(bbl/d)*	**1,005**	1,202
Natural gas *(mcf/d)*	**37,736**	51,445
Average daily production *(boe/d)*	**10,860**	13,596
Sales Prices		
Average oil price *($/bbl)*	**$ 95.03**	$ 101.06
Average natural gas liquids price *($/bbl)*	**$ 58.85**	$ 70.66
Average natural gas price *($/mcf)*	**$ 3.72**	$ 2.27
Corporate Netbacks[(1)]		
Average commodity pricing *($/boe)*	**$ 45.70**	$ 43.35
Royalties *($/boe)*	**$ (3.79)**	$ (4.22)
Net production expenses *($/boe)*[(1)]	**$ (16.52)**	$ (17.65)
Cash G&A *($/boe)*[(1)]	**$ (2.83)**	$ (3.03)
Corporate netbacks *($/boe)*[(1)]	**$ 22.56**	$ 18.45
Wells Drilled *(net)*		
Oil	**3.61**	3.11
Gas	**-**	1.00
Dry	**-**	0.10
Total wells drilled *(net)*	**3.61**	4.26
FINANCIAL *($ thousands, except per share amounts)*		
Petroleum and natural gas revenues, net of royalties	**$ 37,740**	$ 48,509
Cash flow[(1)]	**$ 21,518**	$ 19,174
Per share - basic and diluted *($/share)*	**$ 0.10**	$ 0.09
Net income (loss)	**$ 4,500**	$ (17,091)
Per share - basic and diluted *($/share)*	**$ 0.02**	$ (0.08)
Capital expenditures	**$ 25,046**	$ 23,446
Net debt[(1)]	**$ 64,440**	$ 89,182
Total assets	**$ 617,459**	$ 692,023
Common Shares *(thousands)*		
Weighted average during period		
- basic and diluted	**214,188**	214,188
Outstanding at period end	**214,188**	214,188

(1) Cash flow, net debt, corporate netback, net production expense and cash G&A are non-IFRS measures as defined throughout this MD&A. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

Operations

Petroleum and Natural Gas Production and Sales Volumes

Three months ended March 31				2013				2012
	Oil	Natural Gas Liquids	Natural Gas	Total(1)	Oil	Natural Gas Liquids	Natural Gas	Total(1)
	(bbl/d)	*(bbl/d)*	*(mcf/d)*	*(boe/d)*	*(bbl/d)*	*(bbl/d)*	*(mcf/d)*	*(boe/d)*
Production								
Canada	**1,549**	**1,005**	**36,468**	**8,633**	2,320	1,202	50,533	11,945
Tunisia	**2,016**	**-**	**1,268**	**2,227**	1,499	-	912	1,651
Total(1)	**3,565**	**1,005**	**37,736**	**10,860**	3,819	1,202	51,445	13,596
Sales								
Canada	**1,549**	**1,005**	**36,468**	**8,633**	2,320	1,202	50,533	11,945
Tunisia	**1,161**	**-**	**1,268**	**1,373**	1,526	-	912	1,678
Total(1)	**2,710**	**1,005**	**37,736**	**10,006**	3,846	1,202	51,445	13,623

(1) Totals may not be additive as a result of rounding.

Our predominately crude oil Tunisian production volumes of 2,227 boe per day during the first quarter of 2013, increased by 35% relative to the same period of 2012. This increase entirely reflects the production from our Ordovician oil discovery located on the Bir Ben Tartar Concession ("BBT"). During the first quarter of 2013, we completed our BBT TT10 horizontal well (0.86 net) which accessed the Ordovician Quartzite reservoir. This well was brought on production early during the first quarter, but was temporarily shut-in during the second month of the quarter. The first quarter Tunisian production volume increases also resulted from the BBT TT11, TT13 and TT16 horizontal wells which began producing from the Ordovician Quartzite reservoir during the third and fourth quarters of 2012 (2.58 net wells). The production volumes from these 2012 horizontal wells began to decline during the first quarter of 2013 resulting in lower production volumes relative to the fourth quarter of 2012 but did increase our average production for the first quarter of 2013 by approximately 900 barrels per day relative to the same quarter in 2012. Tunisian crude oil production of 2,016 barrels per day during the first quarter of 2013 exceeded crude oil production from our Canadian operations for the third consecutive quarter.

The difference between our Tunisian production and sales volumes results from crude oil wellhead production being measured in the field versus revenue recognition being measured at the point when crude oil is loaded onto a tanker after first being transported and stored at a terminal facility at the Port of La Skhira. The portion of crude oil production remaining stored in our tanks at each reporting date is reported as inventory. For the first quarter, crude oil production exceeded sales as we had approximately 88,000 barrels of crude oil in inventory at March 31, 2013 as we were awaiting a tanker to take delivery. Assuming that the inventory held at March 31, 2013 had been sold during the first quarter at the subsequently received price of US$100.81 per barrel, the pro forma cash flow, a non-IFRS measure would have been $28.0 million for the first quarter of 2013. Pro forma petroleum and natural gas revenue, assuming the sale of the March 31, 2013 crude oil inventory during the first quarter of 2013, would have increased to $50.2 million.

Production levels of our Canadian segment decreased approximately 3,300 boe per day, or 28%, for the first quarter of 2013 as compared to the same period of 2012. This decrease includes approximately 1,950 boe per day of production associated with the non-core property and various unit dispositions made during 2012 and 2013 and natural reservoir production declines, as partially offset from our Canadian drilling program and a fourth quarter of 2012 property acquisition.

Drilling and completion expenditures for the first quarter totalled $14.6 million (comparable quarter of 2012 - $17.1 million), which included our Tunisian segment's drilling and completion expenditures of $4.0 million (comparable quarter in 2012 - $6.9 million). First quarter Tunisian activity included the completion of our BBT TT10 horizontal well (0.86 net) along with drilling preparations for the horizontal BBT TT12 (0.86 net) well and an exploration well, El Bel, located on our Sud Remada permit, onshore Tunisia. The BBT TT11, TT13 and TT16 horizontal wells, which were completed during the third and fourth quarter of 2012, along with BBT TT10, were the first multi-stage hydraulically fractured horizontal wells in Tunisia, the largest completed to date on the African continent and a successful application of North American drilling and completion technology.

Our Canadian segment's drilling and completion expenditures for the first quarter totalled $10.6 million (comparable quarter of 2012 - $10.2 million) and included the drilling of seven (3.61 net) wells, four (1.75 net) of which were completed in addition to the completion of another three (1.62 net) wells drilled in a previous quarter.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended March 31			2013			2012
($ thousands, except per unit amounts)	Canada	Tunisia	Total[(1)]	Canada	Tunisia	Total[(1)]
Oil sales	**$ 11,524**	**$ 11,657**	**$ 23,181**	$ 18,498	$ 16,877	$ 35,375
$/bbl	**82.65**	**111.54**	**95.03**	87.61	121.51	101.06
Natural gas liquids sales	**$ 5,325**	**$ -**	**$5,325**	$ 7,726	$ -	$ 7,726
$/bbl	**58.85**	**-**	**58.85**	70.66	-	70.66
Natural gas sales	**$ 10,970**	**$ 1,678**	**$ 12,649**	$ 9,292	$ 1,352	$ 10,644
$/mcf	**3.34**	**14.71**	**3.72**	2.02	16.29	2.27
Petroleum and natural gas revenue	**$ 27,819**	**$ 13,336**	**$ 41,155**	$ 35,516	$ 18,229	$ 53,745
$/boe	**35.80**	**107.96**	**45.70**	32.67	119.36	43.35

(1) Totals may not be additive as a result of rounding.

Petroleum and natural gas revenues of $41.2 million during the first quarter of 2013 decreased $12.6 million from the same quarter of 2012. This decrease was mostly due to lower Tunisian pricing and Canadian petroleum pricing, lower Canadian sales volumes and a reduction in Tunisian crude oil sales volumes, despite higher production volumes, resulting from the delayed delivery of crude oil to a tanker. Partially offsetting this decrease was the increase in Canadian natural gas prices and Tunisian natural gas sales volumes, which are liquid rich.

Canadian Petroleum and Natural Gas Revenues and Prices

Our Canadian petroleum and natural gas revenue for the first quarter of 2013, relative to the same quarter of 2012, decreased as a result of lower Canadian petroleum pricing in addition to lower petroleum and natural gas sales volumes resulting from the 2012 and 2013 non-core property dispositions and natural reservoir pressure declines. However, the increase in the received Canadian natural gas price offset the lower natural gas sales volumes and resulted in an increase in natural gas revenue. This is the first reported quarterly increase in Canadian natural gas revenues since the second quarter of 2011.

Tunisian Petroleum and Natural Gas Revenues and Prices

Our Tunisian petroleum and natural gas revenues for the current reporting period, relative to the same quarter of 2012, decreased because of lower realized Brent crude oil pricing and the impact of approximately 88,000 barrels of crude oil production that was held in inventory at the end of the first quarter and not reported as petroleum revenue. As previously discussed, if the inventory held at March 31, 2013 had been sold during the first quarter, the pro forma revenue would have been $22.3 million. This pro forma revenue decreased from that reported in the fourth quarter of 2012 due to production volumes leveling off from the three horizontal wells drilled during 2012.

Benchmark Prices

Three months ended March 31	2013	2012
Oil		
Edmonton par ($/bbl)	**$ 88.21**	$ 92.32
Brent ($US/bbl)	**$ 112.55**	$ 118.49
Natural gas liquids		
WTI[(1)] ($US/bbl)	**$ 94.37**	$ 102.88
Natural gas		
AECO ($/mcf)	**$ 3.25**	$ 2.15

(1) West Texas Intermediate

Crude Oil Pricing

Our first quarter of 2013 average crude oil sales realized a price of $95.03 per barrel, which was six percent lower relative to the same quarter in 2012. This resulted from both lower Edmonton par and Brent benchmark pricing. Our Tunisian crude oil production is sold at the three day average price for Brent oil quotations after being loaded onto a shipping tanker. Consistent with the decrease in the Brent benchmark, our realized Tunisian crude oil price decreased during the first quarter of 2013, as compared to the same quarter of 2012, although the Brent benchmark continued to trade at a premium relative to WTI. Our Canadian conventional crude oil production is sold at prices based on the Edmonton par benchmark postings, which during the first quarter of 2013 continued to trade at a discount relative to WTI. When this discounted Edmonton par price is combined with a weakening WTI benchmark and the price differential for heavy oil, our Canadian crude oil sales price decreased six percent during the first quarter of 2013 as compared to the same quarter of 2012.

Natural Gas Liquids Pricing

Our Canadian natural gas liquids price is a blend of prices received for a range of liquids from ethane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however we benchmark our liquids in reference to Edmonton par or WTI pricing. Relative to Edmonton par, our realized natural gas liquid prices decreased to 67% for the first quarter of 2013 from 77% in the same quarter of 2012 as a surge in liquids rich natural gas drilling industry activity significantly increased the supply. In addition, our price includes the price received for propane, which continued to decrease with an ever widening discount relative to its reference price. When combined with the lower Edmonton par benchmark, our realized natural gas liquids price of $58.85 per barrel decreased by 17% during the first quarter of 2013 relative to the same quarter of 2012.

Natural Gas Pricing

Our Canadian realized natural gas price of $3.34 per mcf for the first quarter of 2013 showed significant improvement from the $2.02 per mcf reported for the same quarter of 2012 and returned it to a realized price not observed since 2011. Our Canadian realized natural gas price reflects the increase in the AECO benchmark price.

Managing Commodity Price Risk

To mitigate commodity price risk which secures cash flows, our management, upon approval of the Board of Directors, has entered into financial derivative contracts which assist us in better managing our future cash flows. This provides more certainty within determined commodities price ranges as to what we will receive on a portion of our crude oil and natural gas sales volumes. Refer to "Commodity Price Risk Management Contracts and Swap Option" for a further discussion on our financial derivative contracts. Our commodity price risk management activities are limited by adherence to a Board approved hedging policy which determines which commodities can be hedged, the maximum notional volume of hedged production, the reference indexed price and terms of hedges.

Royalties

Three months ended March 31			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 3,172**	**$ 243**	**$ 3,415**	$ 4,685	$ 551	$ 5,236
Per sales ($/boe)	**$ 4.08**	**$ 1.96**	**$ 3.79**	$ 4.31	$ 3.61	$ 4.22
Percent of Revenues (%)	**11**	**2**	**8**	13	3	10

For the first quarter of 2013, our royalties of $3.4 million decreased relative to the same quarter of 2012. This reduction was the result of lower Canadian crude oil and natural gas liquids revenues. The change in our commodities mix ratio resulting from our 2012 and 2013 disposition program had the effect of lowering our Canadian operation's royalties per boe and the royalties as a percentage of revenue as reported in the current quarter relative to the same quarter of 2012. The impact of the above on our Canadian royalties per boe was partially offset by the effects of the higher Canadian average natural gas revenue and a decrease in the gas cost allowance recovery from prior periods.

We do not pay royalties on our Tunisian BBT Concession's sales volume which is governed by a profit sharing contract between ourselves and the Tunisian petroleum authority, Entreprise Tunisienne d'Activités Pétrolières ("ETAP"). However, we do pay royalties on a sliding scale calculation with royalty rates of between 2% to 15% from our Adam Concession's sales volumes which is governed by a joint venture contract. Presently, we are paying an average royalty rate on our Adam Concession sales of 9% for natural gas and 12% for crude oil. Despite consistent crude oil production volumes during the first quarter of 2013 relative to the same quarter of 2012 from our Adam Concession, there was an increase in the current reporting period's inventoried crude oil volumes resulting in lower crude oil sales revenue and, correspondingly, a lower royalty expense. Further, as a result of the current reporting period's Tunisian sales volumes being comprised of a higher proportion of production from the BBT Concession, the overall Tunisian royalty rate, as a percentage of revenue decreased to 2% and on a per boe basis to $1.96 per boe for the first quarter of 2013 as compared to the same period of 2012.

Production and Operating Expense

Three months ended March 31			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production and operating expense	**$ 15,020**	**$ 3,259**	**$ 18,279**	$ 20,631	$ 3,900	$ 24,531
Less:						
Processing and gathering revenues	**(3,399)**	**-**	**(3,399)**	(2,654)	-	(2,654)
Net production and operating expense[(1)]	**$ 11,621**	**$ 3,259**	**$ 14,880**	$ 17,977	$ 3,900	$ 21,877
Per sales net production and operating expenses ($/boe)[(1)]	**$ 14.96**	**$ 26.38**	**$ 16.52**	$ 16.54	$ 25.54	$ 17.65
Per sales production and operating expenses ($/boe)	**$ 19.33**	**$ 26.38**	**$ 20.30**	$ 18.98	$ 25.54	$ 19.79

(1) Net production and operating expense and net production and operating expense per boe are non-IFRS measures and are calculated as production and operating expense less processing and gathering income. Management uses the net production and operating expense non-IFRS measure to determine the current periods' cash cost of operating expenses and the net production and operating expense per BOE is used to measure operating efficiency on a comparative basis. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

For the first quarter of 2013, production and operating expense of $18.3 million decreased relative to the same quarter of 2012 because of lower Canadian and Tunisian sales volumes. The increased proportion of sales volumes from our higher operating cost per boe Tunisian segment resulted in an overall higher operating cost per boe.

In Canada, the $15.0 million of production and operating expense for the first quarter of 2013 decreased relative to the same quarter of 2012. This decrease in Canadian operating costs resulted from Canadian dispositions of properties during 2012 and 2013 and our focus on cost savings. We continue to focus on improving our Canadian operating cost structure which has resulted in various process changes and cost saving initiatives. During the first quarter of 2013, relative to the same quarter of 2012, inflationary cost increases and the change in our portfolio of producing properties resulting from our 2012 and 2013 non-core property dispositions caused a slight increase in the operating expenses per boe.

In Tunisia, the decrease in the sales volumes in the first quarter of 2013 as compared to the same quarter of 2012, despite higher production volumes from our BBT Concession, resulted in lower reported operating costs. Operating costs associated with the inventoried crude oil as at March 31, 2013 are not reported on the statement of operations but rather are included as a component of the inventory's carrying amount. These inventoried costs will be reported in the second quarter of 2013 when we sold the associated crude oil volumes.

During the first quarter of 2013, as compared to the same quarter of 2012, the sales volumes from our BBT Concession represented a higher proportion of our Tunisian segment's sale volumes, causing the operating costs per boe to increase. This increase is because under the terms of BBT's profit sharing contract, we pay an 86% interest of the operating expense at this development stage but only receive an estimated revenue interest and attributed volumes at approximately 53%. We forecast improved BBT operating costs on a boe basis as production volumes increase and the planned facility and in-field gathering system come on stream, which is anticipated to occur in 2013.

Processing and gathering revenue is higher for the first quarter of 2013 as compared to the same quarter of 2012. During the first quarter of 2013, we reported higher throughput of third party volumes through our processing facilities and distribution pipelines.

General & Administrative ("G&A") Expense

Three months ended March 31	2013	2012
($ thousands, except where noted)		
G&A expense	**$ 2,722**	$ 4,325
Per sales ($/boe)	**$ 3.02**	$ 3.49
Cash G&A expense[1]	**$ 2,551**	$ 3,762
Per sales ($/boe)	**$ 2.83**	$ 3.03

(1) Cash G&A is a non-IFRS measure and is calculated as G&A less share-based compensation and the amortization of the deferred lease liability. Management uses this non-IFRS measure to assist them in understanding the current period's cash cost of G&A expenses.

G&A expense for the first quarter of 2013 decreased as compared to the same quarter of 2012. This was due to lower staffing and share-based compensation expenses. Lower staffing costs resulted from our decision in November 2012 to reduce Canadian office staffing levels in conjunction with the 2011 and 2012 Canadian non-core property disposition program. Anticipated property dispositions are expected to continue throughout 2013.

Share-based compensation expense decreased for the first quarter of 2013 from the same quarter of 2012 as, during the current reporting quarter, there were no share options granted. As well, certain options vested prior to the beginning of the current reporting period and for those outstanding unvested options there was less fair value remaining to expense.

Corporate Netbacks

The following tables outline the corporate netbacks[1] by country and on a consolidated basis:

Three months ended March 31			2013			2012
Per sales *($/boe)*	Canada[2]	Tunisia	Total	Canada[2]	Tunisia	Total
Realized sales price	**$ 35.80**	**$ 107.96**	**$ 45.70**	$ 32.67	$ 119.36	$ 43.35
Less:						
Royalties	**(4.08)**	**(1.96)**	**(3.79)**	(4.31)	(3.61)	(4.22)
Net production and operating expense [3]	**(14.96)**	**(26.38)**	**(16.52)**	(16.54)	(25.54)	(17.65)
Cash G&A [4]	**(3.07)**	**(1.35)**	**(2.83)**	(3.38)	(0.61)	(3.03)
Corporate netback [1]	**$ 13.69**	**$ 78.27**	**$ 22.56**	$ 8.44	$ 89.60	$ 18.45

(1) Corporate netback is a non-IFRS measure and is calculated as a period's sales of petroleum and natural gas, net of royalties less net production and operating expenses and cash G&A as divided by the period's sales volumes. Management uses this non-IFRS measure to assist us in understanding our profitability relative to current commodity prices and it provides an analytical tool to benchmark changes in operational performance against prior periods.

(2) Canada also includes all corporate G&A expenses associated with the head office.

(3) See production and operating expense table where this non-IFRS measure is defined.

(4) See G&A expense table where this non-IFRS measure is defined.

For the first quarter of 2013, as compared to the same quarter of 2012, our corporate netback increased. This improvement resulted mainly from a higher proportion of this netback being contributed from the relatively higher Tunisian netback, as well as a higher Canadian corporate netback. The corporate netback of $22.56 per boe also represented an increase to 49% of the average realized sales price.

The increase, on a boe basis, in the Canadian corporate netback resulted from an increase in Canadian natural gas pricing and lower expenses as partially offset by lower Canadian petroleum pricing. The Canadian corporate netback includes G&A costs related to our corporate office of $1.50 per boe, which if excluded, would increase the netback by a corresponding amount.

Our Tunisian segment's netback on a boe basis for the first quarter of 2013, relative to the same quarter of 2012, decreased due to lower crude oil and natural gas prices, higher net production and Cash G&A expenses as partially offset by lower royalties. Higher Tunisian net production and lower royalty expenses, on a boe basis, in the first quarter of 2013, as compared to the same quarter of 2012, are a direct result of the impact of our BBT Concession's profit sharing contract and the higher proportion of sales volumes resulting from this Concession. The Tunisian segment's Cash G&A, on a boe basis, is higher due to the inventorying of approximately 88,000 barrels of crude oil at March 31, 2013, which, had these volumes been included in the netback, would have lowered the Tunisian and total Cash G&A to $0.87 per boe and $2.58 per boe, respectively.

Exploration and Evaluation Expense

Three months ended March 31	2013	2012
($ thousands)		
Canada	**$ 3,098**	$ 1,054
Tunisia	**1,401**	2,135
Total	**$ 4,499**	$ 3,189

Exploration and evaluation expense for the first quarter of $4.5 million was higher compared to that reported during the same quarter of 2012. During the first quarter of 2013, management continued our evaluation from December 31, 2012 and determined that a Canadian exploration well that was drilled in 2012 was unsuccessful for petroleum and/or natural gas reserves. Costs incurred on this Canadian exploratory well of $1.4 million were expensed during the first quarter of 2013 through exploration and evaluation expense. The remaining costs were mostly comprised of Canadian and Tunisian exploratory lease rental and geological and geophysical costs for the first quarter of 2013 as directly charged to exploration and evaluation expense, including costs related to a 3D seismic study over our Borj El Khadra onshore exploration permit. This seismic study was approximately 70% complete at March 31, 2013 and is anticipated to be completed during the second quarter of 2013. At that time the data will be evaluated and potential exploration drilling locations identified.

In comparison, during the first quarter of 2012, we drilled our BJA-2 exploration well, located on our Sud Remada exploration permit onshore Tunisia. Subsequent to March 31, 2012, the well was completed but determined to be unsuccessful for petroleum or natural gas reserves. Drilling costs of the BJA-2 exploration well as at March 31, 2012 of $1.5 million, in addition to $1.7 million of exploratory lease rental and geological and geophysical costs, were charged directly to exploration and evaluation expense.

Risk Management Contracts Losses

Three months ended March 31	2013	2012
($ thousands)		
Realized loss on commodity contracts	**$ 11**	$ 265
Unrealized loss on commodity contracts	**593**	6,917
Total	**$ 604**	$ 7,182

We use commodity price risk management contracts to reduce our exposure to fluctuations in commodity prices. As at March 31, 2013 and 2012, the swap and collar commodity price contracts were reported at their fair values as determined through the difference in the referenced market forward prices of the respective commodities over the remaining periods of the contracts as compared to our received prices multiplied by the notional volumes during the remaining periods. As at March 31, 2012, the swap option was reported at a fair value as determined by a Black-Scholes model which included the inputs of a forward WTI price and expected WTI price volatility over the remaining term of the swap option.

The settlement of the Brent based collar commodity price contract for the first quarter of 2013 resulted in a slight realized loss as compared to our realized loss in the same quarter of 2012 resulting from the settlement of both swap and collar commodity price contracts.

Net Financing Expense

Three months ended March 31	2013	2012
($ thousands)		
Interest on bank debt	**$ 1,275**	$ 1,341
Interest earned on bank deposits	**(299)**	(2)
Finance charges and fees	**72**	157
Amortization of deferred financing costs	**61**	-
Accretion of decommissioning obligation	**704**	844
Total	**$ 1,813**	$ 2,340

The decrease in our net financing expenses for the first quarter of 2013, as compared to the same quarter of 2012, resulted from lower average outstanding debt during the current reporting period as partially offset by a higher average interest rate. For the first quarter of 2013, the effective interest rate on our Canadian debt facility was 5.23%, which was higher than the 3.80% for the same quarter of 2012. The higher effective interest rate in the current reporting quarter results from the terms of a new Canadian facility agreement as entered on December 11, 2012.

The accretion expense decrease during the first quarter of 2013, as compared to the same quarter of 2012, resulted from a lower risk free rate, as partially offset by a higher estimated decommissioning obligation.

Depletion, Depreciation and Amortization ("DD&A") Expense

Three months ended March 31	2013	2012
($ thousands, except per unit amounts)		
Canada	**$ 13,768**	$ 21,574
Tunisia	**4,201**	4,469
Total	**$ 17,969**	$ 26,043
Per sales ($/boe)	**$ 19.95**	$ 21.01

DD&A expense for the first quarter of 2013 decreased from the same quarter of 2012 due to a lower carrying amount of our Canadian development and production assets, resulting from the reported impairment during 2012 on our Canadian producing properties. This also resulted in a decrease in DD&A expense per boe relative to the same quarter in 2012. In addition, the decrease in DD&A expense resulted from lower sales volumes and an increase in the estimated time period to amortize our undeveloped acreage costs. The lower Canadian sales volumes resulted from the property dispositions during 2013 and 2012. The lower Tunisian sales volumes, despite higher production volumes, resulted from an increase in inventoried crude oil volumes. Associated depletion costs with inventoried Tunisian crude oil volumes are included in our inventory carrying amount and will be reported in the second quarter of 2013 when these volumes were loaded onto a tanker and sold.

Gains on Disposition of Properties

During the first quarter of 2013, we completed the sale of several petroleum and natural gas properties mostly located throughout Alberta, Canada. Aggregate net proceeds were $13.1 million (2012 - $54.7 million) when combined with the final statements of operating adjustments on prior period petroleum and natural gas property sales. The carrying amount of these properties, including the disposed decommissioning obligation, was less than the sales proceeds received resulting in a gain of $6.3 million for the first quarter of 2013 as compared to $1.3 million for the same quarter of 2012.

Income Tax (Recovery) Expense

Three months ended March 31	2013	2012
($ thousands)		
Current income tax expense	**$ 630**	$ 1,732
Deferred income tax recovery	**(670)**	(77)
Total	**$ (40)**	$ 1,655

Current income taxes relate to our Adam Concession, located onshore Tunisia. The current income tax decrease to $0.6 million during the first quarter of 2013 as compared to the same quarter of 2012, resulted from lower crude oil sales volumes, despite comparable crude oil production volumes, from this Concession.

The deferred income tax recovery of $0.7 million increased for the first quarter of 2013 as compared to the same quarter of 2012. The increase was due to our 3D seismic study costs on our Borj El Khadra exploratory permit. These costs qualify for inclusion within the tax base of our taxable Adam Concession per the Tunisian tax regulations versus being expensed for accounting purposes. We have not reported deferred tax assets because it is not probable that we can utilize these assets against future taxable profit.

Net Income (Loss) and Comprehensive Income (Loss)

Three months ended March 31		2013		2012
($ thousands, except per share amounts)				
Net income (loss)	**$**	**4,500**	$	(17,091)
Per share - basic and diluted ($/share)	**$**	**0.02**	$	(0.08)
Comprehensive income (loss)	**$**	**6,644**	$	(18,645)
Per share - basic and diluted ($/share)	**$**	**0.03**	$	(0.09)
Weighted average shares outstanding - basic and diluted (thousands)		**214,188**		214,188

Our net income of $4.5 million for the first quarter of 2013 increased relative to the net loss in the same quarter of 2012. This increase in net income was due to lower expenses, the realization of the disposition proceeds on a joint arrangement (see “Joint Arrangement”) and higher natural gas and processing & gathering revenues.

The comprehensive income, which includes our net income and a foreign currency translation gain, increased for the first quarter of 2013 as compared to the same quarter in 2012. The increase in comprehensive income is consistent with the increase in the net income plus a foreign currency translation gain on marking-to-market our Tunisian US dollar denominated net assets to the strengthening US dollar, relative to the Canadian dollar. For the first quarter of 2012 we reported a foreign currency translation loss due to the weakening of the US dollar, relative to the Canadian dollar.

Capital Resources, Capital Expenditures and Liquidity

We continue to focus on project economics, scale and repeatability from opportunities in our existing asset base to grow conventional liquids production, test resource play concepts in Canada. In Tunisia we are developing large scale production growth by accelerating the development of our discoveries and existing fields.

During the first quarter of 2013, we completed the sale of Canadian non-core properties with associated volumes totalling approximately 330 boe per day.

Cash flow for the first quarter of 2013, in addition to proceeds from the disposition of Canadian non-core properties, financed the investment in capital, exploration and evaluation expenditures and an increase in non-cash working capital.

Cash Flow

Three months ended March 31		2013		2012
($ thousands, except per share amounts)				
Cash flow from operations	**$**	**3,892**	$	12,378
Add back change in operating non-cash working capital		**13,747**		5,272
Deferred disposition proceeds		**3,051**		-
Add back decommissioning obligation expenditures		**828**		1,524
Cash flow(1)	**$**	**21,518**	$	19,174
Per share - basic and diluted(1)	**$**	**0.10**	$	0.09
Per sales ($/boe)(1)	**$**	**23.90**	$	15.47

(1) Cash flow, cash flow per share and cash flow per boe are non-IFRS measures. Cash flow is calculated from cash flow from continuing operations adjusted for changes in non-cash working capital, deferred disposition proceeds and decommissioning obligation expenditures. Cash flow per share or per boe is calculated from cash flow as previously defined divided by the weighted average basic and dilutive shares outstanding during the period or sales volumes, respectively. Management believes that cash flow is a key measure of our ability to finance capital expenditures and debt repayments. Cash flow as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS and should not be construed as an alternative to cash flow from operations.

Cash flow of $21.5 million for the first quarter of 2013 increased as compared to the same quarter of 2012. This increase was due to lower cash expenses, higher natural gas pricing and a one-time termination of NZOG’s optional right (see “Joint Arrangement”) as partially offset by lower sales volumes and petroleum prices. The increase in our Tunisian inventory decreased the reported cash flow for the first quarter of 2013. On a pro forma basis, assuming the inventory held at March 31, 2013 had been sold at the price received in the second quarter of 2013 of US$100.81 per barrel we would have US$8.9 million in additional revenue, and our pro forma cash flow, after deducting from this pro forma revenue the operating and royalty costs included in the carrying amount of inventory, would have been $27.9 million, a further increase as compared to the first quarter of 2012 cash flow of $19.2 million.

Credit Facilities

($ thousands)	March 31 2013	December 31 2012
Long-term debt	**$ 86,850**	$ 89,137
Less:		
Working capital excluding mark-to-market derivative contracts	**(22,410)**	(16,754)
Net debt(1)	**$ 64,440**	$ 72,383

(1) Net debt and working capital excluding mark-to-market derivate contracts are non-IFRS measures. Net debt is calculated as bank debt adjusted for working capital excluding mark-to-market derivative contracts. Working capital excluding mark-to-market derivative contracts is calculated as current assets less current liabilities both of which exclude derivative contracts and current liabilities excludes the current portion of debt. Management uses net debt to assist us in understanding our liquidity at specific points in time. Mark-to-market derivative contracts are excluded from working capital, in addition to net debt, as management intends to hold each contract through to maturity of the contract's term as opposed to liquidating each contract's fair value or loss.

Our net debt of $64.4 million as at March 31, 2013, decreased relative to $72.4 million as at December 31, 2012 mainly due to a $5.6 million increase in working capital excluding marked-to-market derivative contracts. In addition, an increase in deferred financing costs of $2.3 million related to signing a new credit facility secured by our Tunisian assets lowered the carrying amount of our long-term debt.

On December 11, 2012, we signed a new Canadian reserve-based 364 day revolving credit facility (the "Canadian Revolving Term Credit Facility") with a syndicate of Canadian banks with a maximum availability of $115.0 million. The current revolving period ends on June 27, 2013. In the event that the revolving period is not extended by the banks prior to this date, all amounts then outstanding under the Canadian Revolving Term Credit Facility must be repaid before June 27, 2014. The Canadian Revolving Term Credit Facility is subject to a semi-annual review and redetermination. Changes in the availability of the Canadian Revolving Term Credit Facility are possible, from one renewal period to the next, with draws in excess of availability becoming payable within 60 days. At March 31, 2013 and December 31, 2012 we had drawn $89.5 million on the Canadian Revolving Term Credit Facility resulting in available credit on this facility of $25.5 million. Unamortized deferred financing costs of approximately $0.3 million remained at March 31, 2013 ($0.4 million at December 31, 2012) and will be amortized through to the expiry of the facility in June 2014.

The Canadian Revolving Term Credit Facility is guaranteed by our Canadian subsidiaries and collateralized by floating charges and security interests over all present and future Canadian properties and other Canadian assets and our Canadian subsidiaries. Interest payable on amounts drawn on this facility vary based on Canadian prime, U.S. Base rate, U.S. LIBOR or Bankers' Acceptances depending on the borrowing option we select. The Canadian Revolving Term Credit Facility contains a covenant whereby the ratio of our drawings against this facility and our earnings attributable to the Canadian operations before interest, taxes, depreciation and amortization cannot be greater than 4:1 as determined on a rolling four quarter basis for the most current fiscal quarter. At March 31, 2013, we were in compliance with this covenant.

On March 15, 2013, we signed a US$75.0 million international amortizing reserve-based credit facility ("International Credit Facility") for a term of five years with an international bank. The maximum availability of this facility is US$46.5 million. The International Credit Facility is subject to a semi-annual review and redetermination, where the available amount will be reassessed and outstanding draws must be paid down to the lower of the new available amount or the current repayment commitment. The term of the International Credit Facility can be reduced from the anticipated final maturity date of March 2018 or a date where the estimated reserve recoveries of the borrowing base assets fall below a prescribed rate. The International Credit Facility is collateralized by floating charges and security interests over all of our Tunisian assets, including the shares of our international subsidiaries which have an interest in such assets. Interest payable on drawings from the International Revolving Credit Facility will vary based on a prescribed margin plus U.S. LIBOR. As at March 31, 2013, we had no outstanding drawings against the International Credit Facility. We recognized approximately $2.3 million in deferred financing costs at the time of signing the International Credit Facility, which will be amortized through to the anticipated expiry of this facility.

Capital Expenditures

Three months ended March 31				2013				2012
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 2,533**	**$ -**	**$ -**	**$ 2,533**	$ 389	$ -	$ -	$ 389
Drilling and completions	**10,573**	**3,996**	**-**	**14,569**	10,206	6,943	-	17,149
Facilities and equipment	**3,781**	**2,812**	**-**	**6,593**	3,069	1,776	-	4,845
Field expenditures	**16,887**	**6,808**	**-**	**23,695**	13,664	8,719	-	22,383
Capitalized G&A	**295**	**1,026**	**-**	**1,321**	394	618	-	1,012
Furniture and equipment	**-**	**-**	**30**	**30**	-	-	51	51
Total	**$ 17,182**	**$ 7,834**	**$ 30**	**$ 25,046**	$ 14,058	$ 9,337	$ 51	$ 23,446
Proceeds from dispositions	**$ 13,060**	**$ -**	**$ -**	**$ 13,060**	$ 54,740	$ -	$ -	$ 54,740

Wells Drilled

A summary of our drilling activities for the first quarter of 2013 is as follows:

Three months ended March 31, 2013	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Exploration oil wells	-	**-**	4.00	**2.24**	4.00	**2.24**
Development oil wells	-	**-**	3.00	**1.37**	3.00	**1.37**
Total	-	**-**	7.00	**3.61**	7.00	**3.61**

Canada Capital Expenditures

We participated in the drilling of seven wells (3.61 net) which were rig released during the first quarter of 2013. Five of these wells were targeting oil production from the Dunvegan or Triassic zones in the Grande Prairie core area, one was a Kaybob (West Central Alberta area) Montney oil test, and one was a Doig oil/Montney natural gas test at Red Creek in NE British Columbia. Four of the seven wells drilled in Q1 have been completed and placed on production (all oil wells), the Red Creek well was sold as part of a property divestment, and one Triassic oil well (0.75 net) is awaiting stimulation. Additionally, four (1.99 net) oil wells drilled in 2012 were completed and/or brought on stream during the first four months of 2013. Initial daily production from the wells drilled, completed, or tied-in since the start of the year was approximately 1,300 boe per day net, with about 80% of this production being oil.

The Kaybob area in West Central Alberta contains a developing Montney oil prospect. Our two (0.75 net) Montney horizontal oil wells drilled in 2012 and 2013 were both brought on production in April 2013. The initial production rate of each well was encouraging, but the run time of these wells has been somewhat sporadic due to third party facility issues. We will continue to closely monitor the performance of these and offsetting competitor wells prior to committing to more activity later this year and next. We have identified 12 to 24 horizontal drilling locations, at four to eight wells per section, on 37.5% and 75.0% working interest lands. Two surface pads have been surveyed and could be used to drill up to eight locations.

In the Grande Prairie core area, the bulk of our activity has been focused on crude oil in the Doe Creek and Dunvegan zones, with projects ongoing at Karr, Albright, Beaverlodge, Sinclair, Wapiti, and Grovedale. At Karr, two (0.75 net) horizontal wells were drilled, completed, and brought on production in 2013, resulting in a total of five producing (1.86 net) horizontal Dunvegan wells. Production rates from the property totaled over 500 boe per day net in mid-April 2013. We also acquired three additional sections (1.10 net) of land on the prospect in 2013 and now have up to 30 (11.20 net) horizontal drilling locations identified, with at least one well (0.37 net) planned for 2013.

Late in 2012, we closed a net 280 boe per day (60% oil) property acquisition in the Albright, Beaverlodge, and Sinclair areas. Since then, we have drilled three (1.5 net) horizontal Dunvegan oil wells, conducted one net workover, and acquired 1,120 net acres of contiguous land. All of the new wells were completed and brought on production in the first quarter of 2013, adding 230 boe per day (90% oil) of net production as of mid-April 2013. We plan to drill three (3.00 net) horizontal wells in 2013. We have also identified over 30 horizontal drilling locations on existing acreage, and identified significant optimization and waterflood upside on these properties. We are actively pursuing additional exploration and acquisition opportunities in the area.

No wells have been drilled at Wapiti in 2013, but one (0.37 net) horizontal Dunvegan well drilled in 2012 was tied-in early in 2013, averaging 190 boe per day (70 boe per day net) in its first two months of production. We have identified up to 25 more gross horizontal drilling locations on working interest prospect acreage, and will continue to monitor production from four (1.50 net) working interest producing wells and numerous recent offsetting competitor wells before budgeting more locations.

In addition to the activity discussed, other opportunities that we've currently budgeted for 2013 include horizontal drilling activity in the Grande Prairie core area at Grovedale (Doe Creek oil) and Gordondale (Halfway oil). Other prospects being actively pursued, and where we own significant land positions, include Montney oil in the Gold Creek/Karr area and liquids rich Montney gas in NE British Columbia at Birley.

Tunisia Capital Expenditures

Our BBT Concession's capital activity in first quarter of 2013 included a multi-stage hydraulic fracture stimulation on the TT10 horizontal well (0.86 net). This well was stimulated and brought on production early in the quarter, but experienced production issues resulting in it being temporarily shut-in during February 2013. Plans have been made to install a jet pump to artificially lift production from this well. It's anticipated that this well will be back on production during the second quarter of 2013.

Civil construction for the BBT TT12 horizontal well was completed during the first quarter and the well was spudded during the second quarter of 2013. Civil construction also began on the El Bell EB-1 exploration well during the first quarter of 2013 located on our Sud Remada Permit, onshore Tunisia, and adjacent to our BBT Concession. It is anticipated that the EB-1 well will be drilled during 2013.

During the first quarter of 2013, the facilities and equipment expenditures included the completion of the civil construction of the BBT production facility and the pouring of its pad in addition to completing the order for certain long lead items such as BBT's 13 km gathering system's pipe, bolted tanks, and inlet separators.

Rationalization of Non-Core Properties

During the first quarter of 2013, we completed the sale of several non-core petroleum and natural gas properties located throughout Alberta, Canada, for aggregate net proceeds of $13.1 million, after including the final statements of adjustments for prior period dispositions. The non-core properties sold during the first quarter of 2013 included Red Creek, Gordondale, Lochend and Edwand. Our production from these and the other properties we sold was approximately 330 boe per day. The $13.1 million in funds received for these dispositions were used to partially fund our capital program expenditures of $25.0 million.

We initially assigned fair value from the corporate and asset acquisitions in the first half of 2010 on the same basis to our non-core properties as we did to our core properties. Only after we were able to thoroughly review our acquired property portfolio, were we in a position to identify non-core Canadian properties and commence with the property rationalization process. Through this sequence of events, we have reported gains on sales to date on the majority of our property dispositions.

Joint Arrangement

On March 19, 2013, NZOG Hammamet Pty. Ltd (“NZOG”) and us acknowledged that each had given a negative final investment decision (“FID”) as defined under the terms of the farmout agreement (the “Farmout Agreement”). This terminated NZOG’s optional right to complete its earning and acquisition of an interest in the Cosmos Concession per the terms of the Farmout Agreement. Given this terminated optional right, we reported the initial US$3.0 million cash proceeds we received from NZOG as realized through the line item foreign exchange & other (gains) losses on the condensed consolidated statements of operations and comprehensive income (loss).

Decommissioning Obligation

At March 31, 2013, we have reported a decrease in our decommissioning obligations of $5.3 million from $110.5 million at December 31, 2012 to $105.2 million for the future abandonment and reclamation of our properties. As at March 31, 2013 and December 31, 2012, the estimated obligation includes assumptions in respect of actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred as well as annual inflation of 2.0% in order to calculate the future obligation. A risk-free interest rate of 2.5% was also used in order to present value the obligation. This decrease in the decommissioning obligation resulted from non-core property dispositions, which removed $5.6 million of obligations in addition to $0.8 million of abandonment and reclamation expenditures. Using a discount rate of 10%, the same discount rate applied to our December 31, 2012 2P reserves when we tested for impairment, the decommissioning obligation would be approximately $53.0 million as at March 31, 2013.

Accretion charges of $0.7 million and $0.8 million for the first quarter of 2013 and 2012, respectively, were recognized to reflect the increase in the obligation associated with the passage of time. This decreased accretion charge resulted from a lower risk-free discount rate as partially offset by a higher estimated decommissioning obligation as reported at December 31, 2012. During the first quarter of 2013, additions to the decommissioning liability of $0.4 million mostly related to the quarter’s drilling activities (2012 - $0.4 million).

Outstanding Share Data

Authorized:

- Unlimited number of common shares
- Unlimited number of first preferred shares
- 1,279,000 share purchase warrants (where each share purchase warrant is exercisable to acquire one common share of Chinook at a price of $3.25 per common share on or before June 30, 2013)

Details of share capital, options and warrants outstanding are as follows:

	March 31 2013	December 31 2012
Common shares outstanding	**214,187,681**	214,187,681
Share options	**13,730,419**	13,860,866
Share purchase warrants	**1,279,000**	1,279,000
Fully diluted common shares	**229,197,100**	229,327,547
Weighted average common shares - basic and diluted	**214,187,681**	214,187,681

At May 14, 2013, we had 214,187,681 common shares, 14,982,284 options and 1,279,000 share purchase warrants outstanding.

Commodity Price Risk Management Contracts and Swap Option

Our financial results are influenced by fluctuations in commodity prices. As a means of managing this price volatility, we will enter into commodity price contracts for both crude oil and natural gas. Unsettled risk management contracts are recognized at their approximated fair value on the date of the financial statements. Changes in the fair value of a risk management contract result from volatility in commodity prices and the remaining notional volumes through to the contract's term. Changes in the fair value between reporting periods are recognized in net income (loss) as unrealized risk management contract gains or losses. Realized risk management contract gains or losses are recognized in net income (loss) on unwinding of the financial derivative contract term. While risk management contracts may have opportunity costs when realized commodity prices exceed the contracted price, 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 financing techniques.

At March 31, 2013, we had the following commodity price contracts with an estimated financial liability of $0.6 million:

Indexed Price	Notional Volumes	Company's Received Price	Remaining period
AECO	7,000 GJ/d	$3.20/GJ	April 1, 2013 to December 31, 2013
Brent	500 bbl/d	$95.00 US/bbl to $115.50 US/bbl	April 1, 2013 to December 31, 2013

Subsequent to March 31, 2013, we entered into the following contract:

Indexed Price	Notional Volumes	Company's Received Price	Period
AECO	3000 GJ/d	$3.40/GJ	May 1, 2013 to October 31, 2013

Outlook

Our budgeted production for 2013 remains at 9,500-10,200 barrels of oil equivalent per day with a 40% oil weighting. Cash flow for 2013 is expected to be $95-$100 million on a $102-$107 million capital program split approximately 60% and 40% between Tunisia and Canada. Year-end net debt is expected to be $60-$65 million on combined credit facilities of $161.5 million.

During the last two years, we have actively pursued and implemented multiple strategic initiatives focused on improving our ability to deliver profitable growth for our shareholders and improve our balance sheet to ultimately strengthen our valuation. Although the formal process involving the marketed sale of Canadian non-core assets has been completed, we will continue to evaluate all options and opportunities to unlock value from the various components of our existing asset portfolio over the remainder of 2013. In addition to focusing on organic growth in our core areas of Grande Prairie and Tunisia, efforts to bolster value will include the assessment of acquisitions in our core operating areas, dispositions of non-core assets, prospective business combinations or the split of our domestic and international businesses.

Quarterly Information

Summarized information by quarter for the two years ended March 31, 2013, appears below:

	Mar. 31	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**Jun. 30**
	2013	**2012**	**2012**	**2012**	**2012**	**2011**	**2011**	**2011**
OPERATIONS								
Production								
Oil *(bbl/d)*	**3,565**	4,035	3,516	3,195	3,819	4,206	3,705	3,394
Natural gas liquids *(bbl/d)*	**1,005**	1,003	1,141	1,122	1,202	1,591	1,343	1,329
Natural gas *(mcf/d)*	**37,736**	39,585	43,839	43,387	51,445	55,927	56,364	56,834
Average daily production *(boe/d)*	**10,860**	11,636	11,964	11,548	13,596	15,119	14,443	14,196
Sales Prices								
Average oil price *($/bbl)*	**$ 95.03**	$ 97.72	$ 95.61	$ 89.11	$ 101.06	$ 97.11	$ 94.19	$ 97.71
Average natural gas liquids price *($/bbl)*	**$ 58.85**	$ 57.71	$ 56.42	$ 55.46	$ 70.66	$ 71.23	$ 67.15	$ 67.03
Average natural gas price *($/mcf)*	**$ 3.72**	$ 3.39	$ 2.57	$ 2.08	$ 2.27	$ 3.31	$ 3.84	$ 4.00
Corporate Netbacks[1]								
Average commodity pricing *($/boe)*	**$ 45.70**	$ 51.30	$ 44.67	$ 33.97	$ 43.35	$ 47.00	$ 45.63	$ 44.74
Royalties *($/boe)*	**$ (3.79)**	$ (0.64)	$ (2.50)	$ (3.29)	$ (4.22)	$ (6.03)	$ (5.24)	$ (7.57)
Net production expenses *($/boe)*[1]	**$ (16.52)**	$ (18.98)	$ (18.38)	$ (14.46)	$ (17.65)	$ (17.75)	$ (20.25)	$ (16.96)
Cash G&A *($/boe)*[1]	**$ (2.83)**	$ (4.48)	$ (2.54)	$ (3.74)	$ (3.03)	$ (5.13)	$ (1.80)	$ (1.85)
Corporate netbacks *($/boe)*[1]	**$ 22.56**	$ 27.20	$ 21.25	$ 12.48	$ 18.45	$ 18.10	$ 18.34	$ 18.36
Wells Drilled (net)								
Oil	**3.61**	2.96	1.11	0.86	3.16	6.12	7.45	0.90
Gas	**-**	-	-	-	1.00	1.02	0.65	0.10
Dry	**-**	-	-	0.86	0.10	-	-	-
Total wells drilled *(net)*	**3.61**	2.96	1.11	1.72	4.26	7.14	8.10	1.00
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum and natural gas revenues, net of royalties[2]	**$ 37,740**	$ 55,303	$ 48,012	$ 29,979	$ 48,509	$ 57,274	$ 53,920	$ 47,204
Cash flow[1][2]	**$ 21,518**	$ 28,757	$ 20,935	$ 9,830	$ 19,174	$ 23,950	$ 22,114	$ 17,799
Per share - basic and diluted *($/share)*	**$ 0.10**	$ 0.13	$ 0.10	$ 0.05	$ 0.09	$ 0.11	$ 0.10	$ 0.08
Net income *(loss)*[2][3]	**$ 4,500**	$ (36,708)	$ (12,417)	$ (24,812)	$ (17,091)	$ (58,077)	$ (3,543)	$ (1,890)
Per share - basic and diluted *($/share)*	**$ 0.02**	$ (0.17)	$ (0.06)	$ (0.12)	$ (0.08)	$ (0.27)	$ (0.02)	$ (0.01)
Capital expenditures	**$ 25,046**	$ 50,456	$ 22,674	$ 13,083	$ 23,446	$ 26,343	$ 30,687	$ 18,975
Net debt[1]	**$ 64,440**	$ 72,383	$ 80,428	$ 77,092	$ 89,182	$ 134,900	$ 151,014	$ 165,771
Total assets	**$ 617,459**	$ 622,476	$ 628,542	$ 637,238	$ 692,023	$ 745,403	$ 870,908	$ 864,568
Common Shares *(thousands)*								
Weighted average during period - basic and diluted	**214,188**	214,188	214,188	214,188	214,188	214,188	214,188	214,188
Outstanding at period end	**214,188**	214,188	214,188	214,188	214,188	214,188	214,188	214,188

(1) Cash flow, net debt, corporate netback, net production expense and cash G&A are non-IFRS measures as defined throughout this MD&A. These terms do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

(2) Significant Tunisian crude oil production of 77,000 barrels and 88,000 barrels was not sold at June 30, 2012 and March 31, 2013, respectively.

(3) Includes $43.0 million, $26.5 million and $55.5 million in impairment charges against Canadian properties for the three months ended December 31, 2011, June 30, 2012 and December 31, 2012, respectively.

Factors That Have Caused Variations over the Quarters

The factors described below only apply to the quarterly information presented above.

Generally, our Canadian non-core property disposition program, which commenced in 2011 and continued through the first quarter of 2013, has resulted in a lower trend of Canadian production volumes, especially natural gas and natural gas liquids. This effect was partially offset by increased Tunisian crude oil production from our BBT Concession since the third quarter of 2011. When combined with the increasing trend of the Brent and Edmonton par benchmarks as partially offset by a decrease in the trend of the AECO benchmark, petroleum and natural gas revenues, net of royalties have recovered from the effects of the non-core property disposition program.

Of particular note, the average commodity price, petroleum and natural gas revenues, cash flow and corporate netback per boe for the first quarter of 2013 and the second quarter of 2012 declined as a result of an increase in the relatively higher priced/higher netback Tunisian crude oil production that remained unsold at the end of these quarters. Further, for the fourth quarter of 2011 and second and fourth quarters of 2012, $43.0 million, $26.5 million and $55.5 million, respectively, of impairment charges were reported against our Canadian CGUs resulting in significantly higher net losses during these quarters, in comparison to the other quarters. Comprehensive income essentially trends with net income (loss) but can differ should there be a change in the value of the Canadian dollar relative to the US dollar, the functional currency of our Tunisian operations. Capital expenditures have historically been focused on the Canadian drilling and completions programs but during the second quarter of 2012 shifted, generally, in favor of Tunisian organic growth.

Please refer to "Operations" and other sections of this MD&A for detailed discussions on variations during the comparative quarters and to our previously issued interim and annual management's discussion and analysis for changes in prior quarters.

Risk Factors

Investors should carefully consider the risk factors set out in our December 31, 2012 Annual Information Form ("AIF") and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out in our AIF are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally. If any of the these risks or other risks occur, our business, prospects, financial condition, results of operations and cash flows could be materially adversely impacted.

Additional information on the risks, assumptions and uncertainties are found under the heading "Reader Advisory Regarding Forward-Looking Statements" of our Annual Information Form.

New Standards and Amendment

On January 1, 2013, we adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), and fair value measurements (IFRS 13). We also adopted the amendment to IFRS 7 "Financial Instruments: Disclosures" to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar agreements.

The adoption of these standards and amendment had no impact on the amounts recorded in the condensed consolidated financial statements as at March 31, 2013 nor in the annual consolidated financial statements as at December 31, 2012.

Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to us is made known to our CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in our internal controls over financial reporting were identified during the three months ended March 31, 2013, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

It should be noted that a control system, including our disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Other Information

Forward-Looking Statements

In the interest of providing our shareholders with information about us, including management's assessment of our future plans and operations, certain statements in this MD&A are "forward-looking statements". In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this MD&A speak only as of the date of this document and are expressly qualified by this cautionary statement.

In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: the volume and product mix of our oil and natural gas production on certain newly drilled wells, and the anticipated production volumes therefrom; the anticipated timing of the BBT TT10 well being brought back on production; the timing of the scheduled completion of the BBT TT12 horizontal well; the number of additional wells to be drilled and the timing thereof on the BBT Concession and the Sud Remada permit, and in the case of the BBT Concession, the expected increase in production volumes therefrom; future results from operations and operating metrics; and future development, exploration, acquisition and development activities (including drilling plans) and the timing thereof and related production expectations; as well as management's future expectations regarding production, cash flow, capital expenditures, net debt and credit facilities set out under the heading "Outlook".

With respect to the forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: that we will continue to conduct our operations in a manner consistent with past operations, our ability to continue to operate in Tunisia with limited logistical security and operational issues, future capital expenditure levels, future oil and natural gas prices, future oil and natural gas production levels, our ability to obtain equipment in a timely manner to carry out development activities, the impact of increasing competition, our ability to add production and reserves through development and exploitation activities, the results of seismic and other appraisal activities (including waterflood modeling and seismic data gathering); certain commodity price and other cost assumptions, the continued availability of adequate debt and equity financing and cash flow to fund its planned expenditures. Although we believe that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, political and security risk associated with our Tunisian operations, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve and resource estimates, the continued impact of shut-in production, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in our annual information form for the year ended December 31, 2012 and other documents on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Barrels of Oil Equivalent

Barrels of oil equivalent (boe) is calculated using the conversion factor of 6 mcf (thousand cubic feet) of natural gas being equivalent to one barrel of oil. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl (barrel) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.