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Management's Discussion and Analysis

CHINOOK energy inc

Chinook Energy Inc. | 1000, 517 – 10th Avenue S.W. Calgary, Alberta T2R 0A8 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", "we" or "us") for the three and six months ended June 30, 2014 and 2013 and should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes as at and for the three and six months ended June 30, 2014 and 2013 and our consolidated financial statements and accompanying notes as at and for the years ended December 31, 2013 and 2012. This MD&A is based on information available as at August 13, 2014.

The term "second quarter" and "year to date" or similar terms are used throughout this document and refer to the three and six months ended June 30, 2014, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three and six months ended June 30, 2014, in this respective order. The term "same period of 2013" or similar terms are used throughout this document and refer to the three or six months ended June 30, 2013, depending on the 2014 period under discussion.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2013 ("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 and six months ended June 30, 2014 and 2013 have been prepared in accordance with International Accounting Standard ("IAS") 34 'Interim Financial Reporting' using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board. The condensed consolidated financial statements 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 unit amounts or as otherwise noted. Certain financial measures referred to in this MD&A, such as cash flow, cash flow per share, netback, 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 crude oil and natural gas exploration and development company with crude oil, natural gas and liquids reserves in western Canada and predominately crude oil reserves 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 under the symbol "CKE". Our head office and principal address is Suite 1000, 517 – 10th Avenue S.W., Calgary, Alberta, Canada T2R 0A8.

Our operating and reportable segments for the current reporting periods are as follows:

- Canada – includes our Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in northwestern Alberta and northeastern British Columbia.
- Tunisia – includes eight blocks totaling 2.6 million gross acres located offshore in the Gulf of Hammamet within the Pelagian Basin (Cosmos, Yasmin) and onshore within the Ghadames Basin (Bir Ben Tartar and Adam producing properties and undeveloped onshore blocks).
- Corporate – includes derivative transactions, general and administrative costs and assets held corporately.

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

Share Purchase and Sale Agreement for Tunisian-based Operations Subsidiary

Our wholly-owned subsidiary, Storm Ventures International (BVI) Limited, entered into a share purchase and sale agreement dated as of June 14, 2014 with the subsidiary of an international publicly listed integrated energy company to sell all of the issued and outstanding shares of our wholly-owned subsidiary Storm Ventures International (Barbados) Ltd. ("SVI Barbados") for cash consideration of US$127.7 million, including positive working capital of approximately US$13.7 million, subject to customary closing adjustments (the "Transaction"). SVI Barbados directly and indirectly owns all of our Tunisian segment's operations and the associated net assets in addition to a portion of our Corporate segment. The Transaction is expected to close prior to the end of August 2014. The cash proceeds are anticipated to eliminate our long-term debt position and increase available cash on-hand. The financial effect of our Tunisian segment relative to our consolidated results is detailed throughout this MD&A.

Subsequent to the closing of the Transaction, we will be a pure domestic Canadian oil and natural gas company with a key focus on the development of our Montney and Dunvegan properties. With our recently expanded credit facility of $125.0 million combined with our anticipated increase in cash on-hand, we expect to accelerate the development of our recently announced Montney play at Birley/Umbach where we hold 54 (45 net) sections of land and to continue our Dunvegan development drilling program at Karr and Albright. We would also have the immediate ability to finance strategic acquisitions within our core areas with credit available on our debt facility and cash on hand.

Forward-Looking Information

Statements throughout this MD&A 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 June 30		Six months ended June 30	
	2014	2013	**2014**	2013
OPERATIONS				
Production				
Oil *(bbl/d)*	**3,985**	3,298	**3,830**	3,431
Natural gas liquids *(bbl/d)*	**715**	874	**832**	939
Natural gas *(mcf/d)*	**31,045**	34,458	**30,942**	36,088
Average daily production *(boe/d)*	**9,875**	9,916	**9,818**	10,385
Sales				
Oil *(bbl/d)*	**3,613**	3,588	**3,660**	3,151
Natural gas liquids *(bbl/d)*	**715**	874	**832**	939
Natural gas *(mcf/d)*	**31,045**	34,458	**30,942**	36,088
Average daily sales *(boe/d)*	**9,503**	10,205	**9,648**	10,106
Sales Prices				
Average oil price *($/bbl)*	**$ 107.40**	$ 98.07	**$ 106.61**	$ 96.77
Average natural gas liquids price *($/bbl)*	**$ 72.06**	$ 55.06	**$ 73.22**	$ 57.07
Average natural gas price *($/mcf)*	**$ 5.34**	$ 4.13	**$ 5.88**	$ 3.92
Netback[(1)]				
Average commodity pricing *($/boe)*	**$ 63.71**	$ 53.13	**$ 65.59**	$ 49.47
Royalties *($/boe)*	**$ (7.50)**	$ (4.88)	**$ (6.53)**	$ (4.35)
Net production expenses *($/boe)*[(1)]	**$ (20.91)**	$ (17.31)	**$ (20.17)**	$ (16.92)
Cash G&A *($/boe)*[(1)]	**$ (4.21)**	$ (3.02)	**$ (5.06)**	$ (2.92)
Netback *($/boe)*[(1)]	**$ 31.09**	$ 27.92	**$ 33.83**	$ 25.28
Wells Drilled *(net)*				
Oil	**1.72**	1.77	**8.42**	5.38
Gas	**-**	-	**1.12**	-
Dry	**-**	0.86	**-**	0.86
Total wells drilled *(net)*	**1.72**	2.63	**9.54**	6.24
FINANCIAL *($ thousands, except per share amounts)*				
Petroleum & natural gas revenues, net of royalties	**$ 48,606**	$ 44,805	**$ 103,152**	$ 82,545
Cash flow[(1)]	**$ 23,073**	$ 22,179	**$ 51,522**	$ 43,697
Per share - basic and diluted *($/share)*	**$ 0.11**	$ 0.10	**$ 0.24**	$ 0.20
Net income	**$ 4,391**	$ 3,990	**$ 10,476**	$ 8,490
Per share - basic and diluted *($/share)*	**$ 0.02**	$ 0.02	**$ 0.05**	$ 0.04
Capital expenditures	**$ 27,292**	$ 23,059	**$ 67,683**	$ 48,105
Net debt[(1)]	**$ 80,536**	$ 66,340	**$ 80,536**	$ 66,340
Total assets	**$ 589,515**	$ 621,143	**$ 589,515**	$ 621,143
Common Shares *(thousands)*				
Weighted average during period				
- basic	**214,226**	214,188	**214,207**	214,188
- diluted	**215,814**	214,188	**214,916**	214,188
Outstanding at period end	**214,674**	214,188	**214,674**	214,188

(1) Cash flow, cash flow per share, net debt, 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 June 30				2014				2013
	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	**2,267**	**715**	**29,570**	**7,911**	1,606	874	33,226	8,018
Tunisia	**1,718**	**-**	**1,475**	**1,964**	1,692	-	1,232	1,898
Total(1)	**3,985**	**715**	**31,045**	**9,875**	3,298	874	34,458	9,916
Sales								
Canada	**2,267**	**715**	**29,570**	**7,911**	1,606	874	33,226	8,018
Tunisia	**1,346**	**-**	**1,475**	**1,592**	1,982	-	1,232	2,187
Total(1)	**3,613**	**715**	**31,045**	**9,503**	3,588	874	34,458	10,205

Six months ended June 30				2014				2013
	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	**2,176**	**832**	**29,467**	**7,919**	1,578	939	34,838	8,324
Tunisia	**1,654**	**-**	**1,475**	**1,899**	1,853	-	1,250	2,061
Total(1)	**3,830**	**832**	**30,942**	**9,818**	3,431	939	36,088	10,385
Sales								
Canada	**2,176**	**832**	**29,467**	**7,919**	1,578	939	34,838	8,324
Tunisia	**1,484**	**-**	**1,475**	**1,729**	1,574	-	1,250	1,782
Total(1)	**3,660**	**832**	**30,942**	**9,648**	3,151	939	36,088	10,106

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

Our second quarter Canadian crude oil production achieved its highest production level since the first quarter of 2012. This production increased by 661 barrels of oil per day (“bopd”) compared to the same quarter of 2013. While no new wells were drilled or completed during the second quarter, the equipping and tying-in of our previous winter’s drilling campaign resulted in higher crude oil production during the second quarter. This drilling campaign was focused on the development of our crude oil properties which included Albright, Karr and a Montney prospect at Gold Creek. Specifically, during the first quarter of 2014 we drilled five (3.63 net) wells and completed seven (4.5 net) wells on these properties and one (0.75 net) Montney well in the Birley area.

Our Canadian segment’s drilling and completion expenditures for the second quarter totaled $1.3 million (same quarter of 2013 – $4.2 million) for equipping of our previous winter program’s drilled wells in addition to a well recompletion. As a result of our winter drilling campaign, our Canadian crude oil production increased by 41% and 38% during the current reporting periods, respectively; however our Canadian production levels decreased 107 and 405 barrels of oil equivalent per day (“boepd”), compared to the same periods of 2013. These decreases include approximately 250 and 600 boepd of production associated with our non-core property dispositions made during 2013, in addition to natural reservoir production declines.

During the second quarter, production testing was completed on our first horizontal Montney natural gas well at Birley (0.75 net) while we conducted an extended production test on our Montney oil well (0.37 net) at Gold Creek that was originally tested in the first quarter. The production rates at Gold Creek during this extended test ranged from four to six million cubic feet per day (“mmcfpd”) of sweet natural gas and 470 – 590 bopd (37 degree API). Production facility construction is underway and this well is expected to be on production in September 2014.

Our Montney natural gas well at Birley (0.75 net) was drilled to a depth of 2,700 metres with a 1,220 metre lateral section and completed with an 18 stage fracture stimulation. The well was flow tested through production tubing for 154 hours with test production rates of 1,336 boepd consisting of six mmcfpd of natural gas and 344 barrels per day (“bpd”) of condensate (49 degree API) at 2,700 KPa flowing tubing pressure. This well was brought on production in April through an existing facility that we operate and during its first 30 days of production it produced at a restricted gross rate of 785 boepd, consisting of four mmcfpd of natural gas and 135 bpd of condensate, with flowing tubing pressure of over

7,000 KPa for the entire 30 day production period. Production was shut-in during late May to repair mechanical issues with the facility. Repairs have been completed and the well and facility resumed production in August 2014. In May, we acquired 19 gross (19 net) sections of Montney lands, contiguous with our existing 35 gross (26 net) sections of Montney lands in the Birley/Umbach area.

During the second quarter, Tunisian production volumes of 1,964 boepd increased three percent relative to the same quarter of 2013. Our second quarter Tunisian segment's drilling and completion expenditures were $5.4 million (same quarter of 2013 – $11.3 million) and included drilling and completing the final two (1.72 net) budgeted wells on our Bir Ben Tartar ("BBT") Concession. The TT14 well (0.86 net) was put on production in late May and averaged 486 bopd during its first 30 days and the TT29 well was suspended pending a further review. We also completed a third (0.86 net) well on the BBT Concession that had been drilled during the first quarter of 2014. For the year to date, we have drilled and completed a total of six (5.16 net) wells with five of those wells producing by the end of June. Drilling and completion costs on this six well campaign were below our budgeted gross costs of $4.0 million per vertical well. The net crude oil production from our five new wells totaled approximately 1,077 bopd and 1,051 bopd, respectively, during the current reporting periods.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended June 30			2014			2013
($ thousands, except per unit amounts)	Canada	Tunisia	Total[(1)]	Canada	Tunisia	Total[(1)]
Oil sales	**$ 20,840**	**$ 14,472**	**$ 35,312**	$ 13,509	$ 18,509	$ 32,018
$/bbl	**101.01**	**118.17**	**107.40**	92.43	102.64	98.07
Natural gas liquids sales	**$ 4,690**	**$ -**	**$ 4,690**	$ 4,379	$ -	$ 4,379
$/bbl	**72.06**	**-**	**72.06**	55.06	-	55.06
Natural gas sales	**$ 13,166**	**$ 1,926**	**$ 15,092**	$ 11,314	$ 1,630	$ 12,944
$/mcf	**4.89**	**14.36**	**5.34**	3.74	14.53	4.13
Petroleum and natural gas revenue	**$ 38,696**	**$ 16,398**	**$ 55,094**	$ 29,202	$ 20,138	$ 49,340
$/boe	**53.75**	**113.22**	**63.71**	40.02	101.19	53.13

Six months ended June 30			2014			2013
($ thousands, except per unit amounts)	Canada	Tunisia	Total[(1)]	Canada	Tunisia	Total[(1)]
Oil sales	**$ 38,927**	**$ 31,696**	**$ 70,623**	$ 25,033	$ 30,166	$ 55,199
$/bbl	**98.82**	**118.03**	**106.61**	87.66	105.90	96.77
Natural gas liquids sales	**$ 11,023**	**$ -**	**$ 11,023**	$ 9,703	$ -	$ 9,703
$/bbl	**73.22**	**-**	**73.22**	57.07	-	57.07
Natural gas sales	**$ 29,060**	**$ 3,848**	**$ 32,908**	$ 22,285	$ 3,308	$ 25,593
$/mcf	**5.45**	**14.42**	**5.88**	3.53	14.62	3.92
Petroleum and natural gas revenue	**$ 79,010**	**$ 35,544**	**$ 114,554**	$ 57,021	$ 33,474	$ 90,495
$/boe	**55.12**	**113.55**	**65.59**	37.85	103.78	49.47

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

Petroleum and natural gas revenues of $55.1 million and $114.6 million during the current reporting periods increased $5.8 million and $24.1 million, respectively, from the same periods of 2013. These increases were due to both higher realized weighted average commodities pricing and Canadian crude oil sales volumes.

Canadian Petroleum and Natural Gas Revenue and Prices

Our Canadian petroleum and natural gas revenues of $38.7 million and $79.0 million during the current reporting periods, respectively, increased compared to the same periods of 2013. These increases resulted from both higher realized commodities pricing and crude oil sales volumes. Higher crude oil sales volumes were the result of the focused development of our crude oil properties located near Grande Prairie, Alberta. This development increased our Canadian segment's ratio of the relatively higher priced crude oil production to 29% and 27% of total produced volumes during the current reporting periods, respectively, compared to 20% and 19% in the same periods of 2013.

Tunisian Petroleum and Natural Gas Revenue and Prices

During the second quarter, although we realized a higher crude oil price as a result of both a higher Brent benchmark price and the strengthening of the US dollar relative to the Canadian dollar, our Tunisian petroleum and natural gas revenue decreased despite comparable Tunisian production volumes, compared to the same quarter of 2013. Our crude oil revenue and sales volumes were affected by the 36,000 barrels of crude oil production remaining in inventory at June 30, 2014 as we were waiting for a tanker to take delivery. Crude oil revenue and sales volumes for the comparative quarter were positively affected by the sale of 88,000 barrels of crude oil previously held in inventory further widening the quarterly comparative variance.

During the year to date, our Tunisian petroleum and natural gas revenue increased compared to the same period of 2013. This increase was caused by a higher realized crude oil price that resulted from the factors previously explained.

The difference between our Tunisian production and sales volumes results from crude oil wellhead production being measured in the field versus sales recognition being measured at the point when crude oil is loaded onto a tanker and transfer of title has occurred. The portion of crude oil production that is either in transit from the wellheads or is being stored at terminal facilities awaiting delivery to shipping tankers at each reporting date is reported as inventory.

Benchmark Prices

	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Oil				
Edmonton par ($/bbl)	**$ 106.67**	$ 92.59	**$ 103.42**	$ 90.40
Brent ($US/bbl)	**$ 109.77**	$ 102.46	**$ 108.83**	$ 107.51
Natural gas liquids				
WTI[1] ($US/bbl)	**$ 102.99**	$ 94.22	**$ 100.84**	$ 94.30
Natural gas				
AECO ($/mcf)	**$ 4.76**	$ 3.58	**$ 5.28**	$ 3.41

(1) West Texas Intermediate

All of our produced commodities showed notable benchmark price increases during the current reporting periods compared to the same periods of 2013.

Crude Oil Pricing

Our average realized crude oil sales price for the current reporting periods of $107.40 and $106.61 per barrel increased, respectively, from $98.07 and $96.77 per barrel during the same periods of 2013.

Our Canadian conventional crude oil production is sold at prices based on the Edmonton par benchmark postings as adjusted for quality. This benchmark price increased during the current reporting periods, as did our average realized Canadian crude oil prices, compared to the same periods of 2013.

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 both the increased Brent benchmark price and the relative strengthening of the US dollar, our Canadian dollar reported Tunisian crude oil prices were higher during the current reporting periods, compared to the same periods of 2013.

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. Our realized natural gas liquids prices of $72.06 and $73.22 per barrel for the current reporting periods, respectively, were higher than the same periods of 2013. 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. Relative to Edmonton par, our year to date realized natural gas liquids price increased to 71% from 63% in the same period of 2013. Increases in the realized prices for ethane and propane condensates in excess of the increase in the Edmonton par benchmark resulted in the higher natural gas liquids price and relative ratio.

Natural Gas Pricing

Our Canadian realized natural gas price of $4.89 and $5.45 per mcf for the current reporting periods, respectively, showed significant improvement from the $3.74 and $3.53 per mcf reported for the same periods of 2013. Our Canadian realized natural gas price increases reflect the higher AECO benchmark prices. The increase in the first quarter's North American natural gas price was attributed to a colder than expected winter, particularly in the eastern half of North America, which resulted in larger than expected withdrawals from natural gas storage facilities. Although AECO benchmark pricing has fallen since the first quarter, benchmark pricing in the second quarter remained higher than its comparative period.

Managing Commodity Price Risk

We attempt to mitigate commodity price risk through the use of financial derivative contracts. See "Commodity Price Risk Management Contracts" for a further discussion on our financial derivative contracts.

Royalties

Three months ended June 30			2014			2013
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 6,101**	**$ 387**	**$ 6,488**	$ 3,817	$ 718	$ 4,535
Per sales ($/boe)	**$ 8.47**	**$ 2.68**	**$ 7.50**	$ 5.23	$ 3.61	$ 4.88
Percent of Revenues (%)	**16**	**2**	**12**	13	4	9

Six months ended June 30			2014			2013
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 10,386**	**$ 1,016**	**$ 11,402**	$ 6,989	$ 961	$ 7,950
Per sales ($/boe)	**$ 7.25**	**$ 3.25**	**$ 6.53**	$ 4.64	$ 2.98	$ 4.35
Percent of Revenues (%)	**13**	**3**	**10**	12	3	9

During the current reporting periods, our royalties of $6.5 million and $11.4 million increased, respectively, relative to the same periods of 2013 due to higher petroleum and natural gas revenues. In Canada, these higher revenues partially resulted from higher realized commodity pricing which led to higher royalties overall and on a boe basis. Adjustments to our gas cost allowance and wells coming off royalty holidays also affected our Canadian royalties overall, on a boe basis and as a percentage of revenue.

A decrease in Tunisian sales revenues during the second quarter resulted in lower Tunisian royalties compared to the same period of 2013. In addition, a lower proportion of sales from our royalty paying Adam Concession resulted in a decrease in our Tunisian royalties on a boe basis and as a percentage of revenue. Overall and on a boe basis, Tunisian royalties for the year to date increased as a result of higher crude oil pricing. Our Tunisian segment's royalties result from sales volumes produced from our Adam Concession. We are presently paying an average royalty rate of 9% for natural gas and 12% for crude oil on this Concession's sales volumes. We do not pay royalties on our Tunisian BBT Concession's sales volume which is governed by a production sharing contract between ourselves and ETAP.

Production and Operating Expense

Three months ended June 30			2014			2013
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating	**$ 13,750**	**$ 5,796**	**$ 19,546**	$ 12,655	$ 4,725	$ 17,380
Less:						
Processing & gathering revenues	**(1,466)**	**-**	**(1,466)**	(1,308)	-	(1,308)
Net production & operating expense[(1)]	**$ 12,284**	**$ 5,796**	**$ 18,080**	$ 11,348	$ 4,725	$ 16,072
Per sales net production & operating expenses ($/boe)[(1)]	**$ 17.06**	**$ 40.02**	**$ 20.91**	$ 15.55	$ 23.74	$ 17.31
Per sales production & operating expenses ($/boe)	**$ 19.10**	**$ 40.02**	**$ 22.60**	$ 17.34	$ 23.74	$ 18.71

Six months ended June 30			2014			2013
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating	**$ 27,131**	**$ 10,871**	**$ 38,002**	$ 27,675	$ 7,984	$ 35,659
Less:						
Processing & gathering revenues	**(2,784)**	**-**	**(2,784)**	(4,707)	-	(4,707)
Net production & operating expense[(1)]	**$ 24,347**	**$ 10,871**	**$ 35,218**	$ 22,968	$ 7,984	$ 30,952
Per sales net production & operating expenses ($/boe)[(1)]	**$ 16.99**	**$ 34.73**	**$ 20.17**	$ 15.24	$ 24.75	$ 16.92
Per sales production & operating expenses ($/boe)	**$ 18.93**	**$ 34.73**	**$ 21.76**	$ 18.37	$ 24.75	$ 19.49

(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 revenues. 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.

Our production and operating expense of $19.5 million and $38.0 million for the current reporting periods increased compared to the same periods of 2013 as a result of higher Canadian crude oil sales volumes and higher Tunisian US dollar costs as then reported in more Canadian dollars.

The increases in our Canadian segment's production and operating costs resulted from our shift to higher crude oil production, as our crude oil is generally produced at a higher operating cost per barrel than an energy equivalent volume of our natural gas. Well start-up costs and scheduled plant turnarounds also increased our operating costs overall and on a per boe basis. Partially offsetting these increases were property dispositions during 2013 which caused lower natural gas and natural gas liquids sales volumes. These property dispositions were mostly associated with non-operated volumes for which we were charged higher operating costs on both an average and boe basis.

Our Tunisian operating expenses also increased for the current reporting periods as compared to the same periods of 2013. A component of these increases was the relative strengthening of the US dollar as reported in Canadian dollars. As measured in US dollars, we also observed increases in equipment rentals, a non-operated equalization charge and higher camp costs. These camp costs are relatively fixed-in-nature, but with the conclusion of our six well drilling campaign all of these costs were allocated to operating expense. The sum of these operating expense increases more than offset the effect of lower sales volumes resulting in higher costs per boe. Partially offsetting these increases were lower oil trucking costs resulting from a new contract that we negotiated at the end of 2013.

Canadian processing and gathering revenue decreased during the year to date compared to the same period of 2013. During the prior year to date we reported higher throughput of third party volumes through our processing facilities and distribution pipelines.

General & Administrative ("G&A") Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2014**	2013	**2014**	2013
G&A expense	**$ 3,531**	$ 2,828	**$ 8,696**	$ 5,550
Add back/(deduct):				
Share-based compensation	**(109)**	(290)	**(303)**	(725)
Recovery of bad debts	**(45)**	-	**(65)**	-
Amortization of deferred lease liability	**264**	264	**528**	528
Cash G&A expense(1)	**$ 3,641**	$ 2,802	**$ 8,856**	$ 5,353
Per sales ($/boe)	**$ 4.21**	$ 3.02	**$ 5.06**	$ 2.92

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

G&A expense for the current reporting periods increased compared to the same periods of 2013. This is partially due to lower reported overhead recoveries, mostly from our joint venture partners. The increase in the weighted average working interest of our current operated activities has lowered these overhead recoveries from our partners. Our Tunisian technical staff's assistance on the Transaction also lowered the recoveries we could normally charge to our projects. For the current year to date, we also incurred $1.1 million of incentive compensation in addition to salary increases for our staff. These changes increased cash G&A and, when combined with lower sales volumes, the effect was a further increase in the reported cash G&A on a boe basis during the current reporting periods.

Netback

The following table outlines the netback(1) by country and on a consolidated basis:

Three months ended June 30			**2014**			2013
Per sales ($/boe)	**Canada(2)**	**Tunisia**	**Total**	Canada(2)	Tunisia	Total
Realized sales price	**$ 53.75**	**$ 113.22**	**$ 63.71**	$ 40.02	$ 101.19	$ 53.13
Less:						
Royalties	**(8.47)**	**(2.68)**	**(7.50)**	(5.23)	(3.61)	(4.88)
Net production expense(3)	**(17.06)**	**(40.02)**	**(20.91)**	(15.55)	(23.74)	(17.31)
Cash G&A(4)	**(4.30)**	**(3.78)**	**(4.21)**	(2.76)	(3.95)	(3.02)
Netback(1)	**$ 23.92**	**$ 66.74**	**$ 31.09**	$ 16.48	$ 69.89	$ 27.92

Six months ended June 30			**2014**			2013
Per sales ($/boe)	**Canada(2)**	**Tunisia**	**Total**	Canada(2)	Tunisia	Total
Realized sales price	**$ 55.12**	**$ 113.55**	**$ 65.59**	$ 37.85	$ 103.78	$ 49.47
Less:						
Royalties	**(7.25)**	**(3.25)**	**(6.53)**	(4.64)	(2.98)	(4.35)
Net production expense(3)	**(16.99)**	**(34.73)**	**(20.17)**	(15.24)	(24.75)	(16.92)
Cash G&A(4)	**(5.37)**	**(3.66)**	**(5.06)**	(2.93)	(2.95)	(2.92)
Netback(1)	**$ 25.51**	**$ 71.91**	**$ 33.83**	$ 15.04	$ 73.10	$ 25.28

(1) 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, divided by the period's sales volumes. We use 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 the production and operating expense table where this non-IFRS measure is defined.

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

Our netbacks for the current reporting periods increased 11% and 34%, respectively, compared to the same periods of 2013. These increases were due to higher netbacks from our Canadian segment.

Contributing to the increases in our Canadian netbacks per boe were higher realized crude oil prices and higher proportions of crude oil sales volumes. For the current reporting periods, our Canadian crude oil sales volumes, as a percentage of this segment's total production, increased to 29% and 27%, respectively, compared to 20% and 19% in the same periods of 2013. These increases in the proportion of our Canadian crude oil resulted from our focus on the development of our crude oil weighted properties and the continued disposition of dry natural gas properties throughout 2013. We achieve a higher realized sales price per barrel on our Canadian crude oil sales than we do on an equivalent boe of natural gas resulting in an increased netback. The increases in the Canadian netbacks also resulted from higher natural gas pricing, including the pricing realized for the associated liquids. Although an equivalent boe of natural gas continues to sell at a significant discount relative to a barrel of oil, we realized a 31% and 54% increase in our Canadian natural gas prices during the current reporting periods compared to the same periods of 2013. The current reporting periods' Canadian netbacks include cash G&A costs related to our corporate office of approximately $3.44 and $4.20 per boe compared to $1.92 and $1.90 per boe in the same periods of 2013. These increases resulted from lower sales volumes and overhead recoveries combined with higher compensation.

Although we realized significant Tunisian netbacks of $66.74 and $71.91 per boe during the current reporting periods, we reported modest decreases compared to the same periods of 2013, despite the relative strengthening of the US dollar. These decreases on a US dollar and boe basis mostly resulted from higher net production expenses.

Transaction Costs

During the current reporting periods, we expensed $0.5 million of transaction costs as incurred on the pending sale of SVI Barbados which directly and indirectly owns all of our Tunisian segment's operations and the associated net assets. See "Share Purchase and Sale Agreement for Tunisian-based Operations Subsidiary" for a further discussion of the Transaction.

Exploration and Evaluation Expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2014**	2013	**2014**	2013
Canada	**$ 116**	$ 457	**$ 585**	$ 3,555
Tunisia	**1,230**	3,136	**1,635**	4,537
Total	**$ 1,346**	$ 3,593	**$ 2,220**	$ 8,092

Exploration and evaluation expense decreased during the current reporting periods to $1.3 million and $2.2 million, respectively, compared to $3.6 million and $8.1 million during the same periods of 2013. For the current reporting periods, this expense was entirely due to Canadian and Tunisian pre-licensing evaluation, exploratory lease rental and geological and geophysical costs. For the comparative 2013 year to date period the expense was the result of:

- pre-licensing evaluation, exploratory lease rental and geological and geophysical costs totaling $3.5 million and including costs related to a 3D seismic study over our Borj El Khadra onshore Tunisian exploration permit;
- completion of the evaluation and the subsequent determination that a Canadian exploration well drilled during 2012, at a cost of $1.4 million, was unsuccessful for petroleum or natural gas reserves; and
- Tunisian El Bell well was evaluated as not commercially viable as drilled and cased during the six months ended June 30, 2013 for costs of $3.2 million, including $0.1 million of estimated decommissioning obligations.

Risk Management Contract Losses (Gains)

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2014**	2013	**2014**	2013
Realized losses on derivative contracts	**$ 1,806**	$ 63	**$ 2,998**	$ 74
Unrealized gains (losses) on derivative contracts	**(1,348)**	(1,149)	**1,959**	(556)
Total	**$ 458**	$ (1,086)	**$ 4,957**	$ (482)

We use commodity price risk management contracts to reduce our exposure to fluctuations in commodity prices. We present the fair value assets and liabilities of derivative contracts on the condensed consolidated statements of financial position. Our swap and collar commodity price contracts reported fair values are partially 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.

For the current reporting periods, we realized losses on our AECO and WTI derivative contracts as these benchmark prices averaged above our received fixed price contracts. If we had included these settlements in our commodity revenues, we would have reported adjusted sales prices for the current reporting periods of $4.92 and $5.51 per mcf, respectively, for natural gas compared to our reported prices of $5.34 and $5.88 per mcf. Our reported adjusted sales prices for crude oil would have been $105.55 and $105.15 per barrel for the current reporting periods, respectively, compared to our reported prices of $107.40 and $106.61 per barrel. Our Brent benchmark indexed collar contract resulted in only nominal realized losses during the current reporting periods.

Our unrealized losses for the year to date resulted from our entire commodity benchmarked indexed derivative contracts outstanding on June 30, 2014. Since measured on December 31, 2013, the forward commodity benchmark prices have increased. Our unrealized gains for the second quarter mostly resulted from our AECO benchmarked indexed derivative contracts outstanding on June 30, 2014. Since last measured on March 31, 2014, this forward benchmark price has decreased. Partially offsetting these unrealized gains for the second quarter was a loss on our Brent benchmark contract resulting from an increase in this benchmark's forward prices.

Subsequent to June 30, 2014, we paid $0.1 million to cancel our Brent indexed contract.

Net Financing Expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	2014	2013	2014	2013
Interest on bank debt	**$ 869**	$ 1,357	**$ 1,646**	$ 2,632
Interest earned	**(45)**	(29)	**(175)**	(328)
Finance charges and fees	**246**	77	**445**	149
Amortization of deferred financing costs	**219**	185	**432**	246
Accretion of decommissioning obligation	**716**	676	**1,423**	1,380
Total	**$ 2,005**	$ 2,266	**$ 3,771**	$ 4,079

The decrease in our interest on bank debt for the current reporting periods, compared to the same periods of 2013, resulted from lower average effective interest rates. Our average effective interest rates during the current reporting periods of 4.0% and 3.9%, respectively, decreased from 5.2% in the same periods of 2013. These decreased interest rates partly resulted from our election in the fourth quarter of 2013 to take the Bankers' Acceptances interest rates on the majority of our drawings, which are currently lower than the previously elected Canadian prime rate, and adjustments to the applicable rate based on our improved Canadian EBITDA. A decrease in the average outstanding debt balance also contributed to the lower interest on bank debt for the year to date, as compared to the same period of 2013. As further discussed in the "Credit Facilities" section of this MD&A, we have the option to change the basis of our effective interest rate on our Canadian revolving credit facility.

During 2013, we incurred $2.7 million of deferred financing costs associated with the signing of an international credit facility and are amortizing these fees over this facility's anticipated remaining term, which currently is estimated at four years. This international credit facility is discussed further in the "Credit Facilities" section of this MD&A.

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

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	2014	2013	2014	2013
Canada	**$ 12,346**	$ 13,462	**$ 24,633**	$ 27,230
Tunisia	**5,222**	6,206	**10,524**	10,407
Total	**$ 17,568**	$ 19,668	**$ 35,157**	$ 37,637
Per sales ($/boe)	**$ 20.32**	$ 21.18	**$ 20.13**	$ 20.58

DD&A expense during the current reporting periods, on an overall dollar and per boe basis, decreased compared to the same periods of 2013 as we reported lower overall sales volumes. The decrease in sales volumes for the second quarter resulted from lower Tunisian sales volumes compared to the same quarter of 2013, as 36,000 barrels of crude oil production were held in inventory at June 30, 2014 as we were waiting for a tanker to take delivery. Sales volumes for the comparative quarter were also positively affected by the sale of 88,000 barrels of crude oil as previously held in inventory. Depletion costs associated with inventoried Tunisian crude oil volumes are included in our inventory carrying amount and are reported as depletion in the period when the crude oil is sold. The decrease in sales volumes for the year to date resulted from our Canadian 2013 non-core property disposition program. The decrease in our second quarter DD&A expense on a boe basis was caused by an increase in the proportion of our total sales volumes originating from our Canadian segment. Our Canadian segment's depletion rate on a boe basis, which has improved during the year to date, is lower than that of our Tunisian segment.

Impairment of Development & Production Assets

The potential sale of the Tunisian operations and its associated net assets (see "Share Purchase and Sale Agreement for Tunisian-based Operations Subsidiary"), was assessed as a trigger of potential impairment of our two Tunisian cash generating units' ("CGUs") net carrying values at June 30, 2014. We conduct testing for impairment at the CGU level by comparing each CGU's carrying value to the recoverable value. This recoverable value is the higher of the CGU's fair value or value in use. For our offshore Tunisian CGU, our carrying value at June 30, 2014 approximated its fair value. We assessed this CGU's recoverable value based on a measure of its contingent resource using relative fair value third party market transactions for offshore North African early stage development projects with contingent resources. Given the uniqueness of such a project, third party market transactions were not always directly comparable resulting in significant measurement uncertainty. Testing of our onshore Tunisian CGU's recoverable value relative to its carrying value did not result in an impairment at June 30, 2014. Our onshore Tunisian CGU's recoverable amount was estimated using expected after tax future cash flows generated from proved reserves, using a discount rate of 15% and forward commodity price estimates.

At June 30, 2014, we determined that there were no indications of impairment that would warrant conducting an impairment test in respect of any of our Canadian CGUs. In addition, we determined that there were no sustained indicators that a recovery of prior periods' impairment was warranted at this time.

Gains on Disposition of Properties

During the current reporting periods we completed the sale of petroleum and natural gas properties resulting in a gain of $0.2 million compared to a gain of $11.7 million in the same period of 2013.

Income Tax Expense (Recovery)

	Three months ended June 30		Six months ended June 30	
($ thousands)	2014	2013	2014	2013
Current income tax expense	**$ 1,062**	$ 2,309	**$ 2,993**	$ 2,939
Deferred income tax (recovery) expense	**(95)**	530	**(320)**	(140)
Total	**$ 967**	$ 2,839	**$ 2,673**	$ 2,799

The reported current income taxes are from our Adam Concession located onshore Tunisia. These taxes decreased in the second quarter compared to the same quarter of 2013. This decrease was due to lower crude oil revenues caused by lower sales volumes, resulting in lower taxable income.

We had deferred income tax recoveries of $0.1 million and $0.3 million during the current reporting periods compared to an expense of $0.5 million and a recovery of $0.1 million in the same periods of 2013. The current periods' recoveries mostly resulted from a decrease in the valuation allowance applied against our Canadian net operating loss carry forwards. We were able to use some of these previous years' tax loss carry forwards to offset against the current periods' Canadian segment's taxable income. We do not anticipate incurring Canadian corporate taxes in the near term given we had Canadian non-capital losses carried forward of $177.0 million at December 31, 2013. We have not reported deferred tax assets because it is not probable that we can utilize these assets against future taxable profit.

Based on our initial assessment, our Canadian company's investment in Storm Ventures International (BVI) Limited has sufficient tax pools to allow us to repatriate the proceeds on the sale of our Tunisian operations and associated net assets to Canada without incurring any tax effects.

Net Income and Comprehensive (Loss) Income

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	2014	2013	2014	2013
Weighted average shares outstanding - basic (thousands)	**214,226**	214,188	**214,207**	214,188
Dilutive impact of share options, restricted awards and performance awards (thousands)	**1,588**	-	**709**	-
Weighted average shares outstanding - diluted (thousands)	**215,814**	214,188	**214,916**	214,188
Net income	**$ 4,391**	$ 3,990	**$ 10,476**	$ 8,490
Net income per share - basic & diluted ($/share)	**$ 0.02**	$ 0.02	**$ 0.05**	$ 0.04
Comprehensive (loss) income	**$ (169)**	$ 8,589	**$ 10,658**	$ 15,233
Comprehensive (loss) income per share ($/share) - basic and diluted	**$ (0.00)**	$ 0.04	**$ 0.05**	$ 0.07

Our net income of $4.4 million and $10.5 million in the current reporting periods increased relative to the same periods of 2013. These increases resulted from higher realized commodity pricing, an increase in Canadian crude oil sales volumes and lower exploration and evaluation expenses, despite decreases in gains on property dispositions to $0.1 million for the current reporting periods from $5.5 million and $11.7 million in the second quarter of 2013 and year to date 2013, respectively.

Comprehensive (loss) income includes our net income and foreign currency translation losses and gains of our US dollar denominated Tunisian operations. We realized foreign currency translation losses during the second quarter as the Canadian dollar strengthened. For the year to date, it was the inverse situation. Should the pending sale of our Tunisian operations close, we will report accumulated other comprehensive income as realized foreign exchange gains. As at June 30, 2014, this measure was $6.4 million.

Capital Resources, Capital Expenditures and Liquidity

We continue to focus on project economics, scale and repeatability from our core Canadian asset base to grow conventional petroleum and natural gas production and test resource play concepts.

For the year to date, cash flow from operations, cash on deposit and a credit facility drawing financed the investment in capital, decommissioning expenditures, exploration and evaluation expenditures (including our sizeable land acquisition) and an increase in non-cash working capital.

The potential closing of the share purchase and sale agreement for the disposition of our Tunisian operations will allow us to focus on our Canadian operations which are currently showing improving operational results.

Cash Flow

	Three months ended June 30		Six months ended June 30	
($ thousands, except per share amounts)	**2014**	**2013**	**2014**	**2013**
Cash flow from operations	**$ 32,067**	$ 21,850	**$ 40,668**	$ 25,742
Add back (deduct):				
Change in operating non-cash working capital	**(9,551)**	(256)	**9,692**	13,491
Deferred disposition proceeds	**-**	-	**-**	3,051
Decommissioning obligation expenditures	**557**	585	**1,162**	1,413
Cash flow[(1)]	**$ 23,073**	$ 22,179	**$ 51,522**	$ 43,697
Per share - basic and diluted[(1)]	**$ 0.11**	$ 0.10	**$ 0.24**	$ 0.20
Per sales ($/boe)[(1)]	**$ 26.68**	$ 23.88	**$ 29.50**	$ 23.89

(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 to assess 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.

Our year to date cash flow increased by 18% to $51.5 million compared to the same period of 2013. This increase is partially due to higher Canadian crude oil sales volumes and their higher netback, compared to the netback of an equivalent boe of natural gas. Stronger realized Canadian commodity pricing during the year to date, compared to the same period of 2013, also contributed to both the higher netback and our reported increase in cash flow. Cash flow for the second quarter was relatively consistent with the same quarter of 2013 as the higher Canadian crude oil sales volumes and their associated netback were offset by the same Tunisian measures, despite comparable production volumes. The year to date period of 2013 included deferred disposition proceeds associated with the one-time termination of a potential partner's optional right to complete its earning and acquisition of an interest in our Cosmos Concession. If these deferred disposition proceeds had not been included in our 2013 cash flow, our increase in the year to date cash flow compared to the same period of 2013 would have been over 25%.

Credit Facilities

($ thousands)	**June 30 2014**	**December 31 2013**
Long-term debt	**$ 95,501**	$ 75,897
Less:		
Working capital excluding mark-to-market derivative contracts	**(14,965)**	(14,048)
Net debt[(1)]	**$ 80,536**	$ 61,849

(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 $80.5 million at June 30, 2014, increased relative to $61.8 million at December 31, 2013 due primarily to capital, exploration and decommissioning expenditures of $71.5 million exceeding our cash flow of $51.5 million combined with a foreign currency translation gain of $0.4 million on our US dollar held cash. During the year to date we drew an additional $19.3 million from our Canadian credit facility, which in addition to the non-cash amortization of the deferred financing fees, resulted in an increase to our outstanding long-term debt. As at June 30, 2014, our drawn debt and borrowings were $97.8 million compared to $78.5 million at December 31, 2013.

On June 25, 2014, we extended the current revolving period of our Canadian reserve-based 364 day revolving credit facility (the "Canadian Revolving Term Credit Facility"), which we hold with a syndicate of Canadian banks, to June 25, 2015 and the maximum availability of the facility was increased to $125.0 million (December 31, 2013 - $115.0 million). On June 25, 2015, the facility's revolving period and availability will be reassessed and in the event that the revolving period is not extended further by the banking syndicate, all amounts then outstanding under the facility must be repaid before June 24, 2016. 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 June 30, 2014, our drawings under the facility and borrowings of $97.8 million as well as outstanding letters of credit of $0.3 million against the Canadian Revolving Term Credit Facility resulted in available credit on this facility of $26.9 million (December 31, 2013 - $78.5 million, $0.4 million and $36.1 million, respectively).

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 charged on amounts drawn on this facility vary based on the applicable pricing rate combined with the Bankers' Acceptances rates, which is the current interest rate option that we have selected for the majority of our drawings. Other interest rate options that we can select are the Canadian prime rate, US Base rate and US LIBOR. The Canadian Revolving Term Credit Facility contains a covenant whereby the ratio of our debt or borrowed money which include drawings against this facility, to our earnings attributable to the Canadian operations before interest, taxes, depreciation/depletion and amortization cannot be greater than 4:1 as determined on a rolling four quarter basis for the most current fiscal quarter. As at June 30, 2014, we were in compliance with this covenant and anticipate being in compliance through the existing term of this facility.

On March 15, 2013, we signed a US$75.0 million international amortizing reserve-based credit facility (the "International Credit Facility") for a term of five years with an international bank. Effective January 1, 2014, our available borrowing base on the facility was reduced to US$23.8 million (December 31, 2013 – US$46.5 million). This reduction was due to an increase in estimated future costs, as included in our December 31, 2013 reserve report for our Tunisian producing properties, over the facility's remaining four year term despite an increase in these reserves' estimated net recoverable values. At June 30, 2014 and December 31, 2013, we had no outstanding drawings against the International Credit Facility. The International Credit Facility's next semi-annual review is scheduled for December 2014 where the available amount will be reassessed and any 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 in March 2018 to a date when 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. Interest payable on drawings from the International Credit Facility will be cancelled.

Immediately prior to closing the share purchase and sale agreement for the disposition of our Tunisian operations and associated net assets, and consistent with the sale of our collateralized international subsidiaries, the International Credit Facility will be cancelled.

Unamortized deferred financing costs of approximately $2.3 million remained at June 30, 2014 and will be amortized through to the anticipated expiry of each facility's term. The majority of this deferred financing cost will be expensed should the International Credit Facility be cancelled immediately prior to closing the sale of our Tunisian operations and associated net assets.

Capital Expenditures

Three months ended June 30				2014				2013
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 14,041**	**$ -**	**$ -**	**$ 14,041**	$ 229	$ -	$ -	$ 229
Drilling and completions	**1,279**	**5,383**	**-**	**6,662**	4,226	11,266	-	15,492
Facilities and equipment	**3,410**	**294**	**-**	**3,704**	777	4,811	-	5,588
Field expenditures	**18,730**	**5,677**	**-**	**24,407**	5,232	16,077	-	21,309
Capitalized G&A	**281**	**543**	**-**	**824**	272	1,428	-	1,700
Furniture and equipment	**-**	**-**	**-**	**-**	-	-	50	50
Acquisitions	**-**	**2,061**	**-**	**2,061**	-	-	-	-
Total	**$ 19,011**	**$ 8,281**	**$ -**	**$ 27,292**	$ 5,504	$ 17,505	$ 50	$ 23,059
Proceeds from dispositions	**$ 33**	**$ -**	**$ -**	**$ 33**	$ 3,360	$ -	$ -	$ 3,360

Capital Expenditures (continued)

Six months ended June 30				2014				2013
($ thousands)	Canada	Tunisia	Corporate	Total	Canada	Tunisia	Corporate	Total
Land and lease	**$ 14,202**	**$ -**	**$ -**	**$ 14,202**	$ 2,762	$ -	$ -	$ 2,762
Drilling and completions	**19,722**	**21,110**	**-**	**40,832**	14,799	15,262	-	30,061
Facilities and equipment	**7,866**	**520**	**-**	**8,386**	4,558	7,623	-	12,181
Field expenditures	**41,790**	**21,630**	**-**	**63,420**	22,119	22,885	-	45,004
Capitalized G&A	**541**	**1,355**	**-**	**1,896**	567	2,454	-	3,021
Furniture and equipment	**-**	**-**	**306**	**306**	-	-	80	80
Acquisitions	**-**	**2,061**	**-**	**2,061**	-	-	-	-
Total	**$ 42,331**	**$ 25,046**	**$ 306**	**$ 67,683**	$ 22,686	$ 25,339	$ 80	$ 48,105
Proceeds from dispositions	**$ 33**	**$ -**	**$ -**	**$ 33**	$ 16,420	$ -	$ -	$ 16,420

Wells Drilled

A summary of our drilling activities for the second quarter and year to date is as follows:

Three months ended June 30, 2014	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Oil	2.00	**1.72**	-	**-**	2.00	**1.72**
Total	2.00	**1.72**	-	**-**	2.00	**1.72**

Six months ended June 30, 2014	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Oil	6.00	**5.16**	4.00	**3.26**	10.00	**8.42**
Gas	-	**-**	1.00	**0.37**	1.00	**0.37**
Development wells	6.00	**5.16**	5.00	**3.63**	11.00	**8.79**
Exploration gas well	-	**-**	1.00	**0.75**	1.00	**0.75**
Total	6.00	**5.16**	6.00	**4.38**	12.00	**9.54**

Canada Capital Expenditures

Canadian activity in the second quarter was highlighted by a Crown land purchase at Birley/Umbach in northeastern British Columbia, offsetting our first horizontal Montney natural gas well (0.75 net) drilled during the first quarter of 2014. We acquired 19 additional sections of 100% working interest land in the Birley/Umbach area at the May land sale, bringing the total number of contiguous sections in this play to 54 (45 net). Our first horizontal well (0.75 net) drilled in this area during the first quarter of 2014, was tested during the second quarter at gross rates of six mmcfpd of natural gas and 344 barrels of condensate per day and was back on production in August of 2014. We expect to drill and complete a second horizontal well on these lands in the third quarter of 2014.

During the second quarter, we conducted an extended production test on the Gold Creek, Alberta area horizontal Montney oil well (0.37 net) that was originally drilled and tested in the first quarter of 2014. The production rates during the extended test ranged from four to six mmcfpd of sweet gas and 470 – 590 barrels of 37 degree API oil per day. Construction of a production facility is underway and this well is expected to be on production late in the third quarter of 2014.

We did not conduct any drilling operations during the second quarter of 2014. Our planned third quarter drilling activity will include the horizontal well (0.75 net) at Birley/Umbach and two (2 net) horizontal Dunvegan oil wells at Albright near Grande Prairie, Alberta, which includes re-drilling the horizontal section of a well drilled during the first quarter of 2014. At our non-operated Karr property, we have budgeted four (1.37 net) wells to be drilled prior to the end of 2014.

Tunisia Capital Expenditures

Capital activity on our BBT Concession during the second quarter consisted of drilling and completing two (1.72 net) wells and completing one (0.86 net) well that was drilled during the first quarter of 2014. All six (5.16 net) wells of our 2014 well program have now been drilled and completed and five (4.3 net) wells have been brought on production.

Drilling and completion activity at our BBT Concession for the second quarter consisted of:

- We completed the TT19 well (0.86 net), which had been drilled during the preceding quarter. We brought this well on production in early April and during the first 30 days of production the well averaged 186 bopd with basic sediment and water below four percent.
- We drilled and completed the TT14 well (0.86 net) and brought this well on production in mid-May. The average gross rate for the first 30 days of production was 486 bopd with negligible basic sediment and water.
- The TT29 well (0.86 net) was drilled and completed. The well is currently suspended and is under additional evaluation as to its use as a producer or a future water source well.

The non-operated Adam Concession and BEK Permit had little expenditure activity during the second quarter. Planning is underway to drill one (0.05 net) development well on the Adam Concession and one (0.10 net) exploration well on the BEK Permit pending government review of this permit.

For our offshore properties, Cosmos and Yasmin, the acquisition expenditure represents the costs paid during the current reporting periods for the gross overriding royalty and product bonus agreements that we initially signed during 2008 as a component of the consideration we paid to third a party to acquire these properties at that time.

Decommissioning Obligation

At June 30, 2014, we had decommissioning obligations of $91.3 million (December 31, 2013 – $90.4 million) for the future abandonment and reclamation of our properties. This increase resulted primarily from additions related to our year to date drilling program of $0.8 million (same period of 2013 – $0.8 million) and accretion charges. The recognized accretion charges reflect the increase in the obligation associated with the passage of time. For the current reporting periods, accretion charges of $0.7 million and $1.4 million, respectively, were comparable to the charges reported during the same periods of 2013. Offsetting the year to date increases were decreases related to the disposition of non-core properties of $0.1 million and abandonment and reclamation expenditures of $1.2 million (same period of 2013 – $8.7 million and $1.4 million, respectively).

As at June 30, 2014 and December 31, 2013, 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. As at June 30, 2014 and December 31, 2013, a risk-free interest rate of up to 3.2% was used in order to calculate the present value of the obligation.

Outstanding Share Data

Authorized:

- Unlimited number of common shares
- Unlimited number of first preferred shares

Details of share capital and share awards outstanding are as follows:

	June 30 2014	December 31 2013
Common shares outstanding	**214,673,953**	214,187,681
Share options	**11,875,221**	14,319,699
Restricted awards	**165,675**	-
Performance awards	**129,765**	-
Weighted average common shares		
- basic	**214,207,186**	214,187,681
- diluted	**214,916,314**	214,187,681

As at August 12, 2014, we had 214,850,532 common shares, 11,104,057 share options, 165,675 restricted awards and 129,765 performance awards outstanding.

Share Award Incentive Plan

On June 26, 2014, we granted 165,675 restricted awards and 129,765 performance awards pursuant to our Restricted and Performance Award Incentive Plan (the "Share Award Incentive Plan").

Subject to the terms and conditions of the Share Award Incentive Plan, restricted awards and performance awards will entitle the holder to a sum (the "Award Value") to be paid in equal tranches on the first and second anniversaries of the date of grant (the "Payment Date") of such restricted awards or performance awards, as applicable. In the case of restricted awards, the Award Value is calculated at the Payment Date(s) by multiplying the number of restricted awards by the fair market value of our common shares. The fair market value is determined on the applicable Payment Date as the volume weighted average trading price of our common shares on the Toronto Stock Exchange (or other stock exchange on which the common shares may be listed) for the five trading days immediately preceding such date.

With respect to performance awards, on each Payment Date, or such other dates as may be determined by the Compensation, Nominating and Corporate Governance Committee (the “Committee”) of our Board of Directors, the holder will be entitled to an amount equal to one-half of the Award Value underlying such performance awards multiplied by a payout multiplier. The payout multiplier is determined by the Committee based on an assessment of the achievement of the pre-defined corporate performance measures in respect of the applicable period. The payout multiplier for a particular period can range from one-half to two depending on the point within the target range that we satisfy the corporate performance measures. Annually, prior to the Payment Date in respect of any performance award, the Committee shall assess our performance for the applicable period.

On the applicable Payment Date, we shall, at our sole and absolute discretion, have the option of settling the Award Value to which a holder of restricted awards or performance awards is entitled in the form of either cash or in common shares which we may either acquire on the stock exchange on which our common shares may be listed from time to time or issued from our treasury, or some combination thereof. Our current non-binding intention is to settle the Award Value in common shares and we have therefore accounted for the fair value of the restricted awards and performance awards as though they will be equity-settled. Provided we maintain this intention and settle the Award Value through the issuance of common shares, we will continue to account for the restricted awards and performance awards as equity-settled throughout their vesting period.

The fair value of issued restricted awards and performance awards is determined as of their grant date using the market price of our common shares adjusted for an estimated forfeiture rate. The fair value of the performance awards is further adjusted by an estimated payout multiplier. As prescribed for equity-settled awards, this fair value is reported over the restricted and performance awards’ vesting periods with no subsequent adjustments for changes in the trading price of our common shares. See “New Accounting Amendments and Interpretation and Significant Accounting Policy” for additional discussion.

Commodity Price Risk Management Contracts

To mitigate commodity price risk, we, with the approval of our Board of Directors, have 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. Our commodity price risk management activities are limited by adherence to a policy of our Board which determines which commodities may be subject to such contracts, the maximum contracted notional production volume, the referenced indexed price and the contractual terms.

Unsettled risk management contracts are recognized at their approximated fair value on the date of the condensed consolidated 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 as unrealized risk management contract gains or losses. Realized risk management contract gains or losses are recognized in net income on unwinding of the financial derivative contract term. While risk management contracts may have opportunity costs when commodity benchmarks exceed the contracted prices, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. We continuously review the need to utilize such financing techniques.

As at June 30, 2014, we had the following commodity price contracts with an estimated fair value current liability of $3.5 million:

Indexed Price	Notional Volumes	Company's Received Price	Remaining Contractual Term
AECO	5,000 GJ/d	$3.25/GJ to $3.50/GJ	July 1, 2014 to December 31, 2014
AECO	5,000 GJ/d	$3.68/GJ	July 1, 2014 to December 31, 2014
AECO	5,000 GJ/d	$3.5025/GJ	July 1, 2014 to October 31, 2014
WTI	500 bbl/d	$101.30/bbl	July 1, 2014 to December 31, 2014
Brent	500 bbl/d	US$98.00/bbl to US$108.00/bbl	July 1, 2014 to December 31, 2014

Based on guidance, these price risk contracts are expected to secure our received commodity prices on approximately 26% and 43% of sales volumes from crude oil and Canadian natural gas, respectively.

Outlook

The first half of 2014 was a pivotal and exciting period for us. Our encouraging Montney drilling results at Birley/Umbach and Gold Creek and our planned follow up activity on these properties has the potential to provide us with a multi-year drilling inventory to support meaningful growth and profitability.

The significant conditions precedent and requisite approvals needed to close the sale of our Tunisian operations have been met and we anticipate that the transaction will close prior to the end of August 2014, three months ahead of our previous estimate of December 1, 2014. We will provide updated guidance concurrent with our closing announcement. The sale of our international business will allow us to focus on our domestic business at a time when our Canadian operational results and key play economics are improving.

Quarterly Information

Summarized information by quarter for the two years ended June 30, 2014, appears below:

	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	Jun. 30 2013	Mar. 31 2013	Dec. 31 2012	Sept. 30 2012
OPERATIONS								
Production								
Oil *(bbl/d)*	**3,985**	3,672	3,356	3,456	3,298	3,565	4,035	3,516
Natural gas liquids *(bbl/d)*	**715**	950	722	753	874	1,005	1,003	1,141
Natural gas *(mcf/d)*	**31,045**	30,839	33,612	35,820	34,458	37,736	39,585	43,839
Average daily production *(boe/d)*	**9,875**	9,761	9,680	10,180	9,916	10,860	11,636	11,964
Sales								
Oil *(bbl/d)*	**3,613**	3,707	3,725	3,558	3,588	2,710	4,264	3,929
Natural gas liquids *(bbl/d)*	**715**	950	722	753	874	1,005	1,003	1,141
Natural gas *(mcf/d)*	**31,045**	30,839	33,612	35,820	34,458	37,736	39,584	43,839
Average daily sales *(boe/d)*	**9,503**	9,797	10,049	10,282	10,205	10,006	11,865	12,377
Sales Prices								
Average oil price *($/bbl)*	**$ 107.40**	$ 105.83	$ 98.57	$ 104.46	$ 98.07	$ 95.03	$ 97.72	$ 95.61
Average natural gas liquids price *($/bbl)*	**$ 72.06**	$ 74.10	$ 63.74	$ 62.36	$ 55.06	$ 58.85	$ 57.71	$ 56.42
Average natural gas price *($/mcf)*	**$ 5.34**	$ 6.42	$ 3.99	$ 3.00	$ 4.13	$ 3.72	$ 3.39	$ 2.57
Netback(1)								
Average commodity pricing *($/boe)*	**$ 63.71**	$ 67.44	$ 54.46	$ 51.17	$ 53.13	$ 45.70	$ 51.30	$ 44.67
Royalties *($/boe)*	**$ (7.50)**	$ (5.57)	$ (4.61)	$ (3.30)	$ (4.88)	$ (3.79)	$ (0.64)	$ (2.50)
Net production expenses *($/boe)*(1)	**$ (20.91)**	$ (19.44)	$ (19.32)	$ (19.28)	$ (17.31)	$ (16.52)	$ (18.98)	$ (18.38)
Cash G&A *($/boe)*(1)	**$ (4.21)**	$ (5.91)	$ (3.10)	$ (2.46)	$ (3.02)	$ (2.83)	$ (4.48)	$ (2.54)
Netback *($/boe)*(1)	**$ 31.09**	$ 36.52	$ 27.43	$ 26.13	$ 27.92	$ 22.56	$ 27.20	$ 21.25
Wells Drilled *(net)*								
Oil	**1.72**	6.70	1.65	3.86	1.77	3.61	2.96	1.11
Gas	**-**	1.12	-	-	-	-	-	-
Dry	**-**	-	-	-	0.86	-	-	-
Total wells drilled *(net)*	**1.72**	7.82	1.65	3.86	2.63	3.61	2.96	1.11
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties(2)	**$ 48,606**	$ 54,545	$ 46,088	$ 45,285	$ 44,805	$ 37,740	$ 55,303	$ 48,012
Cash flow(1)(2)	**$ 23,073**	$ 28,449	$ 20,179	$ 23,146	$ 22,179	$ 21,518	$ 28,757	$ 20,935
Per share - basic and diluted ($/share)	**$ 0.11**	$ 0.13	$ 0.09	$ 0.11	$ 0.10	$ 0.10	$ 0.13	$ 0.10
Net income (loss)(2)(3)	**$ 4,391**	$ 6,085	$ (39,002)	$ 3,812	$ 3,990	$ 4,500	$ (36,708)	$ (12,417)
Per share - basic and diluted ($/share)	**$ 0.02**	$ 0.03	$ (0.18)	$ 0.02	$ 0.02	$ 0.02	$ (0.17)	$ (0.06)
Capital expenditures	**$ 27,292**	$ 40,391	$ 14,162	$ 20,961	$ 23,059	$ 25,046	$ 50,456	$ 22,674
Net debt(1)	**$ 80,536**	$ 74,390	$ 61,849	$ 65,105	$ 66,340	$ 64,440	$ 72,383	$ 80,428
Total assets	**$ 589,515**	$ 604,419	$ 555,341	$ 593,192	$ 621,143	$ 617,459	$ 622,476	$ 628,542
Common Shares *(thousands)*								
Weighted average during period - basic	**214,226**	214,188	214,188	214,188	214,188	214,188	214,188	214,188
Weighted average during period - diluted	**215,814**	214,245	214,188	214,188	214,188	214,188	214,188	214,188
Outstanding at period end	**214,674**	214,188	214,188	214,188	214,188	214,188	214,188	214,188

(1) Cash flow, cash flow per share, net debt, netback, net production expense and cash G&A are non-IFRS measures as defined and calculated 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, 88,000 barrels and 36,000 barrels was not sold at September 30, 2012, March 31, 2013 and June 30, 2014, respectively.

(3) Includes $55.5 million in impairment charges against Canadian properties for the three months ended December 31, 2012 and $35.5 million in impairment charges against Canadian and Tunisian properties for the three months ended December 31, 2013.

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 2013, 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 from the fourth quarter of 2011 until the third quarter of 2013, at which time our drilling program was delayed, and increased Canadian crude oil production resulting from the partial reinvestment of our disposition proceeds into core area crude oil properties. When combined with the effect of the Brent, Edmonton par and AECO benchmarks, which have generally trended up since the third quarter of 2012, petroleum and natural gas revenues, net of royalties, have recovered from the effects of the non-core property disposition program. This, in turn, when combined with an increased proportion of produced crude oil, and this commodity's higher associated netback, relative to the total volumes, generated sufficient cash flow to generally reduce our net debt throughout 2012 and 2013. This has allowed us to avoid having to access the equity markets. Our upfront active drilling programs during the first quarter and our sizeable acquisition of Montney lands in the second quarter, resulted in higher net debt during 2014.

Of particular note, as a result of an increase in the relatively higher priced/higher netback Tunisian crude oil production that remained unsold at the end of the first quarter of 2013 and the second quarter of 2014, the average commodity sales price, petroleum and natural gas revenues, cash flow and netback per boe declined for these quarters. Further, for the fourth quarter of 2012, \$55.5 million of impairment charges were reported against our Canadian CGUs, while in the fourth quarter of 2013, \$32.0 million and \$3.5 million of impairment charges were reported against our offshore, non-producing Tunisian CGU and a Canadian CGU, respectively, 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 generally focused on our Tunisian organic growth, however; since the third quarter of 2013 capital expenditures related to our Canadian drilling and completions programs increased as we pursued oil opportunities in our core areas. We saw a reduction in our Tunisian capital expenditures in the third and fourth quarter of 2013 as we were awaiting the additional governmental approvals that were granted at the end of the fourth quarter of 2013 and led to an increase in Tunisian capital expenditures during the first quarter.

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 Annual Information Form for the year ended December 31, 2013 ("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 they 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 adversely affected in a material way.

Additional information on the risks, assumptions and uncertainties are found under the heading "Forward-Looking Statements".

New Accounting Amendments and Interpretation and Significant Accounting Policy

New Accounting Amendments and Interpretation

We adopted the following new amendments and interpretation:

- Amendments to IAS 32, Financial Instruments: Presentation, and
- IFRS Interpretation Committee ("IFRIC") 21, Levies.

The adoption of these amendments and interpretation had no material impact on our financial results recorded in our consolidated financial statements as at June 30, 2014 and December 31, 2013.

Significant Accounting Policy

Share-based Compensation

a) Share Award Incentive Plan

On March 25, 2014, our Board of Directors approved the establishment of the Share Award Incentive Plan. On May 14, 2014, our shareholders approved the issuance of common shares from our treasury pursuant to this plan. Restricted awards and performance awards granted pursuant to the Share Award Incentive Plan may be settled at our option, in our sole and absolute discretion, in the form of either cash or in common shares which may either be acquired by us on the stock exchange on which our common shares may be listed from time to time or issued from our treasury, or some combination thereof. The fair value of the restricted awards and performance awards is determined as of their grant date based on the market price of our common shares adjusted for an estimated forfeiture rate. The fair value of the performance awards is further adjusted by an estimated payout multiplier. Share-based compensation expense, included in the line item general & administrative expense on our condensed consolidated statements of operations and comprehensive (loss) income, is recorded over the period that the restricted awards and performance awards vest, with a corresponding increase to contributed surplus on our condensed consolidated statements of financial position, on the basis that the award is expected to be equity settled. Forfeitures are re-estimated throughout the vesting period based on past experience and future expectations with a final adjustment upon actual vesting. The expected life of these granted awards is adjusted based on our best estimate for the effects of non-transferability and exercise restrictions. When either the restricted awards or performance awards vest they are immediately settled, at which time the related fair value amounts previously recorded in contributed surplus are reclassified to share capital.

b) Share Option Plan (cashless exercise feature)

Share options granted pursuant to our share option plan are intended to be settled through the issuance of our common shares. The fair value of share options is determined on their grant date using the Black-Scholes option pricing model. Share-based compensation expense, included in the line item general & administrative expense on our condensed consolidated statements of operations and comprehensive (loss) income, is recorded over the period that the share options vest, with a corresponding increase to contributed surplus on our condensed consolidated statements of financial position. Forfeitures are re-estimated throughout the vesting period based on past experience and future expectations with a final adjustment upon actual vesting. When share options are exercised, the proceeds, together with the amounts recorded in contributed surplus, are recorded in share capital. The cashless exercise of share options results in a portion of the optionee's share options being forfeited in consideration for the share option exercise price. Upon exercise, the consideration we received plus the amount previously recorded as contributed surplus are recognized as share capital.

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 period beginning on April 1, 2014 and ended on June 30, 2014, 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 and readers 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: various matters related to the Transaction disclosed herein including the anticipated closing date and the amount of the proceeds of the Transaction; that our future operating costs should begin to decline; wells budgeted for the remainder of the year including expected timing of the drilling and completion of a second horizontal well in the Birley/Umbach area; the expected time that our Gold Creek horizontal oil well is expected to be on production; the volume and product mix of our oil and natural gas production on certain newly drilled wells, and the anticipated production volumes therefrom; anticipated operational and cost efficiencies; operations to be conducted, wells to be drilled and/or completed and the timing thereof on certain of our Canadian properties and, in certain cases, the expected increase in production volumes resulting 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.

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 exploration and development activities, all costs in respect of certain wells being accurately estimated, certain commodity price and other cost assumptions, the continued availability of adequate debt financing and cash flow to fund our 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 risks 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, environmental risks, competition from other producers, inability to retain drilling rigs and other services, unexpected 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, inability to access sufficient capital from internal and external sources and unanticipated increased or unforeseen costs. 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, 2013 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.