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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", "we" or "us") for the three and six months ended June 30, 2013 and 2012 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, 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 August 14, 2013.

The terms "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, 2013, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three and six month periods ended June 30, 2013. The term "same period of 2012" or similar terms are used throughout this document and refer to the three or six month periods ended June 30, 2012 depending on the 2013 period under discussion.

Additional Information

Additional information on our company, 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 and six months ended June 30, 2013 and 2012 have been prepared in accordance with IAS 34 'Interim Financial Reporting' 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. Our producing properties are Bir Ben Tartar and Adam.
- **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 June 30		Six months ended June 30	
	2013	2012	**2013**	2012
OPERATIONS				
Production				
Oil *(bbl/d)*	**3,298**	3,195	**3,431**	3,507
Natural gas liquids *(bbl/d)*	**874**	1,122	**939**	1,162
Natural gas *(mcf/d)*	**34,458**	43,387	**36,088**	47,417
Average daily production *(boe/d)*	**9,916**	11,548	**10,385**	12,573
Sales				
Oil *(bbl/d)*	**3,588**	2,385	**3,151**	3,116
Natural gas liquids *(bbl/d)*	**874**	1,122	**939**	1,162
Natural gas *(mcf/d)*	**34,458**	43,387	**36,088**	47,417
Average daily sales *(boe/d)*	**10,205**	10,738	**10,106**	12,181
Sales Prices				
Average oil price *($/bbl)*	**$ 98.07**	$ 89.11	**$ 96.77**	$ 96.49
Average natural gas liquids price *($/bbl)*	**$ 55.06**	$ 55.46	**$ 57.07**	$ 63.32
Average natural gas price *($/mcf)*	**$ 4.13**	$ 2.08	**$ 3.92**	$ 2.18
Corporate Netbacks(1)				
Average commodity pricing *($/boe)*	**$ 53.13**	$ 33.97	**$ 49.47**	$ 39.22
Royalties *($/boe)*	**$ (4.88)**	$ (3.29)	**$ (4.35)**	$ (3.81)
Net production expenses *($/boe)*(1)	**$ (17.31)**	$ (14.46)	**$ (16.92)**	$ (16.24)
Cash G&A *($/boe)*(1)	**$ (3.02)**	$ (3.74)	**$ (2.92)**	$ (3.35)
Corporate netbacks *($/boe)*(1)	**$ 27.92**	$ 12.48	**$ 25.28**	$ 15.82
Wells Drilled *(net)*				
Oil	**1.77**	0.86	**5.38**	4.02
Gas	**-**	-	**-**	1.00
Dry	**0.86**	0.86	**0.86**	0.96
Total wells drilled *(net)*	**2.63**	1.72	**6.24**	5.98
FINANCIAL *($ thousands, except per share amounts)*				
Petroleum & natural gas revenues, net of royalties	**$ 44,805**	$ 29,979	**$ 82,545**	$ 78,488
Cash flow(1)	**$ 22,179**	$ 9,830	**$ 43,697**	$ 29,004
Per share - basic and diluted *($/share)*	**$ 0.10**	$ 0.05	**$ 0.20**	$ 0.14
Net income (loss)	**$ 3,990**	$ (24,812)	**$ 8,490**	$ (41,903)
Per share - basic and diluted *($/share)*	**$ 0.02**	$ (0.12)	**$ 0.04**	$ (0.20)
Capital expenditures	**$ 23,059**	$ 13,083	**$ 48,105**	$ 36,529
Net debt(1)	**$ 66,340**	$ 77,092	**$ 66,340**	$ 77,092
Total assets	**$ 621,143**	$ 637,238	**$ 621,143**	$ 637,238
Common Shares *(thousands)*				
Weighted average during period				
- basic and diluted	**214,188**	214,188	**214,188**	214,188
Outstanding at period end	**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.

Operations

Petroleum and Natural Gas Production and Sales Volumes

Three months ended June 30				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	**1,606**	**874**	**33,226**	**8,018**	1,764	1,122	42,396	9,952
Tunisia	**1,692**	**-**	**1,232**	**1,898**	1,431	-	991	1,596
Total[1]	**3,298**	**874**	**34,458**	**9,916**	3,195	1,122	43,387	11,548
Sales								
Canada	**1,606**	**874**	**33,226**	**8,018**	1,764	1,122	42,396	9,952
Tunisia	**1,982**	**-**	**1,232**	**2,187**	621	-	991	786
Total[1]	**3,588**	**874**	**34,458**	**10,205**	2,385	1,122	43,387	10,738

Six months ended June 30				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	**1,578**	**939**	**34,838**	**8,324**	2,042	1,162	46,465	10,949
Tunisia	**1,853**	**-**	**1,250**	**2,061**	1,465	-	952	1,624
Total[1]	**3,431**	**939**	**36,088**	**10,385**	3,507	1,162	47,417	12,573
Sales								
Canada	**1,578**	**939**	**34,838**	**8,324**	2,042	1,162	46,465	10,949
Tunisia	**1,574**	**-**	**1,250**	**1,782**	1,074	-	952	1,232
Total[1]	**3,151**	**939**	**36,088**	**10,106**	3,116	1,162	47,417	12,181

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

Our predominately crude oil Tunisian production volumes of 1,898 boe per day and 2,061 boe per day during the current reporting periods, increased by 19% and 27%, respectively, relative to the same periods of 2012. The crude oil production increase was entirely from our Ordovician oil discovery located on the Bir Ben Tartar Concession ("BBT"). During the second quarter we drilled and completed the TT12 horizontal well (0.86 net). This well was brought on production late during the second quarter but initial production shows high water cuts and lower than expected oil rates. The second quarter Tunisian production volume increases also resulted from the BBT TT10, TT11, TT13 and TT16 horizontal wells which began producing either during the first quarter of 2013 or the second half of 2012 (3.44 net wells). These horizontal wells increased our average production for the current reporting periods by approximately 640 barrels of oil per day and 760 barrels of oil per day, respectively, relative to the same periods in 2012. Tunisian crude oil production has exceeded crude oil production from our Canadian operations for the past four consecutive quarters. Current net production from BBT is 1,770 barrels of oil per day with TT21 and TT20 to be completed and TT4 to be recompleted and brought onto production in the third quarter of 2013. The increased Tunisian natural gas sales volumes for the current reporting periods, as compared to the same periods in 2012, were from our Adam Concession and resulted from an increase in sales pipeline capacity allowing previously flared gas to be sold.

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 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 second quarter, crude oil sales exceeded production as we sold approximately 88,000 barrels that were produced in the first quarter of 2013, partially offset by the approximately 60,000 barrels of crude oil that remained in inventory at June 30, 2013 as we were awaiting a tanker to take delivery. Assuming that sales volumes were reported on a production volume basis and that the inventory held at June 30, 2013 was sold at the subsequently received price of US$106.04 per barrel, the respective second quarter pro forma cash flow and revenue, non-IFRS measures, would have decreased, to $20.8 million and $47.1 million whereas it would have increased for the year to date 2013 to $47.6 million and $95.6 million.

Production levels of our Canadian segment decreased approximately 1,900 and 2,600 boe per day for the current reporting periods, respectively, as compared to the same periods of 2012. These decreases include approximately 1,200 and 2,100 boe per day of production during the current reporting periods, associated with non-core property dispositions made during 2012 and 2013 in addition to natural reservoir production declines and non-operated and third party facility downtime. These decreases were partially offset by production from our Canadian drilling program, a December 2012 property acquisition and, because of the recent improvement in natural gas pricing, our placing back onto production certain dry natural gas properties which were previously shut-in.

Drilling and completion expenditures for the second quarter totalled $15.5 million (comparable quarter of 2012 - $8.3 million), which included our Tunisian segment's drilling and completion expenditures of $11.3 million (comparable quarter in 2012 - $6.8 million). Second quarter Tunisian activity included the drilling and completion of the TT12 horizontal well (0.86 net) and the drilling of our TT21 well (0.86 net), in addition to the drilling of a side track on our non-operated Karma 2 well (0.05 net) located on our producing onshore Adam Concession.

We continue to monitor costs, drilling efficiencies and well performance and accordingly adjust our near term BBT development plans. Vertical well costs have improved materially due to substantial well cost reductions resulting from improved optimization of drilling and completions from over $5.0 million, on a gross basis in 2011 to $4.0 million today, with a projected future cost of $3.5 million. These lower costs on vertical wells allows us to step further away from existing well control to improve our understanding of the reservoir structure and sand distribution across the 50km^2 field area which will in turn improve the future placement and orientation of the lateral section of each horizontal well.

The iterative process we are experiencing is not unusual in the early stages of a new play such as the one at BBT. The horizontal wells have exceeded our base expectations from a volume perspective, but have introduced the issue of water production which we did not encounter with the vertical wells. Water cuts remain stable and three of our four hortizonal wells that have enough history to develop a trend, are at or above our base case type curve. We are working to improve the horizontal well economics with both an improved understanding of the reservoir (fracture and well orientation) and with operational efficiencies (well design and water shut offs) and expect a mix of horizontal and vertical wells to be drilled as we continue to appraise and develop the reservoir.

As well, we have been installing jet pump systems as production declines to the point of requiring some form of artificial lift. Jet pump systems are preferred over pumpjacks in Tunisia as they do not require a service rig to run the pump. Although we are encouraged by the early results, for future applications we are working to improve the logistics, costs, availability and uptime of these jet pump systems.

Our Canadian segment's drilling and completion expenditures for the second quarter of $4.2 million (comparable quarter of 2012 - $1.5 million) were limited due to spring breakup conditions that makes it difficult to access certain areas. These operations were focused in the Grande Prairie area and included the recompletion of a well in an uphole natural gas zone and the drilling and completion costs associated with a Red Creek well prior to its disposition. In addition, we began drilling on a three (3.0 net) well project on our Albright and Beaverlodge properties.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended June 30			2013			2012
($ thousands, except per unit amounts)	Canada	Tunisia	Total[1]	Canada	Tunisia	Total[1]
Oil sales	**$ 13,509**	**$ 18,509**	**$ 32,018**	$ 13,022	$ 6,315	$ 19,337
$/bbl	**92.43**	**102.64**	**98.07**	81.14	111.72	89.11
Natural gas liquids sales	**$ 4,379**	**$ -**	**$ 4,379**	$ 5,662	$ -	$ 5,662
$/bbl	**55.06**	**-**	**55.06**	55.46	-	55.46
Natural gas sales	**$ 11,314**	**$ 1,630**	**$ 12,944**	$ 6,699	$ 1,495	$ 8,194
$/mcf	**3.74**	**14.53**	**4.13**	1.74	16.57	2.08
Petroleum and natural gas revenue	**$ 29,202**	**$ 20,138**	**$ 49,340**	$ 25,383	$ 7,810	$ 33,193
$/boe	**40.02**	**101.19**	**53.13**	28.03	109.13	33.97

Six months ended June 30			2013			2012
($ thousands, except per unit amounts)	Canada	Tunisia	Total[1]	Canada	Tunisia	Total[1]
Oil sales	**$ 25,033**	**$ 30,166**	**$ 55,199**	$ 31,521	$ 23,191	$ 54,712
$/bbl	**87.66**	**105.90**	**96.77**	84.82	118.68	96.49
Natural gas liquids sales	**$ 9,703**	**$ -**	**$ 9,703**	$ 13,388	$ -	$ 13,388
$/bbl	**57.07**	**-**	**57.07**	63.32	-	63.32
Natural gas sales	**$ 22,285**	**$ 3,308**	**$ 25,593**	$ 15,991	$ 2,847	$ 18,838
$/mcf	**3.53**	**14.62**	**3.92**	1.89	16.43	2.18
Petroleum and natural gas revenue	**$ 57,021**	**$ 33,474**	**$ 90,495**	$ 60,900	$ 26,038	$ 86,938
$/boe	**37.85**	**103.78**	**49.47**	30.56	116.10	39.22

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

Petroleum and natural gas revenues of $49.3 million and $90.5 million during the current reporting periods increased $16.1 million and $3.6 million, respectively, from the same periods of 2012. These increases were largely due to both higher average Canadian petroleum and natural gas realized pricing and Tunisian crude oil and natural gas sales volumes. Partially offsetting these increases were lower Canadian sales volumes and a decrease in Tunisian crude oil and natural gas pricing.

Canadian Petroleum and Natural Gas Revenue and Prices

Canadian petroleum and natural gas revenue increased during the second quarter as compared to the same period of 2012, due to higher average Canadian crude oil and natural gas realized pricing. This was the first reported quarterly increase in Canadian petroleum and natural gas revenue since the fourth quarter of 2011. During the current year to date reporting period, the Canadian petroleum and natural gas revenues decreased by six percent as compared to the same period of 2012, as the effect of these higher prices was more than offset by a decrease in Canadian sales volumes.

Tunisian Petroleum and Natural Gas Revenue and Prices

Tunisian petroleum and natural gas revenue increased for the second quarter and year to date, relative to the same periods of 2012, because of higher production and sales volumes from our BBT Concession.

Benchmark Prices

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Oil				
Edmonton par *($/bbl)*	**$ 92.59**	$ 84.03	**$ 90.40**	$ 88.17
Brent *($US/bbl)*	**$ 102.46**	$ 108.90	**$ 107.51**	$ 113.72
Natural gas liquids				
WTI[1] *($US/bbl)*	**$ 94.22**	$ 93.50	**$ 94.30**	$ 98.19
Natural gas				
AECO *($/mcf)*	**$ 3.58**	$ 1.90	**$ 3.41**	$ 2.02

(1) West Texas Intermediate

Crude Oil Pricing

Our second quarter average crude oil sales realized price of $98.07 per barrel increased from $89.11 per barrel during the same quarter in 2012 and was comparable on a year to date basis.

Canadian conventional crude oil production is sold at prices based on the Edmonton par benchmark postings as adjusted for quality. This benchmark increased during the current reporting periods, as did our average realized Canadian crude oil price, as compared to the same periods in 2012.

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 current reporting periods, as compared to the same periods of 2012.

In the current reporting periods our total crude oil price as reported in Canadian dollars was also affected by the increase in the proportion of the relatively higher priced Tunisian crude oil sales and the strengthening of the US dollar.

Natural Gas Liquids Pricing

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 year to date realized natural gas liquid price decreased to 63% from 72% in the same period 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 partially offsetting higher Edmonton par benchmark, our year to date realized natural gas liquids price of $57.07 per barrel decreased by 10% relative to the same period of 2012.

Natural Gas Pricing

Canadian realized natural gas price of $3.74 and $3.53 per mcf for the second quarter and year to date 2013, respectively, showed significant improvement from the $1.74 and $1.89 per mcf reported for the same periods of 2012. We have not realized these price levels since 2011. Our Canadian realized natural gas price reflects the increase in the AECO benchmark price.

Managing Commodity Price Risk

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

Royalties

Three months ended June 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 3,817**	**$ 718**	**$ 4,535**	$ 3,003	$ 211	$ 3,214
Per sales *($/boe)*	**$ 5.23**	**$ 3.61**	**$ 4.88**	$ 3.32	$ 2.95	$ 3.29
Percent of Revenues *(%)*	**13**	**4**	**9**	12	3	10

Six months ended June 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Royalties	**$ 6,989**	**$ 961**	**$ 7,950**	$ 7,688	$ 762	$ 8,450
Per sales *($/boe)*	**$ 4.64**	**$ 2.98**	**$ 4.35**	$ 3.86	$ 3.40	$ 3.81
Percent of Revenues *(%)*	**12**	**3**	**9**	13	3	10

For the second quarter, our royalties of $4.5 million increased relative to the same quarter of 2012. This increase was the result of higher Canadian and Tunisian royalties. The increased Canadian royalties resulted from both higher crude oil and natural gas revenues. Since these revenue increases were derived from higher realized prices, the Canadian royalties on a boe basis also increased while royalties as a percentage of revenues remained relatively unchanged. The increased Tunisian royalties resulted from an increase in Tunisian sales from our royalty paying Adam Concession. The increased proportion of Tunisian sales derived from this Concession resulted in higher royalty costs on a boe basis, despite lower crude oil pricing. Presently we are paying an average royalty rate of 9% for natural gas and 12% for crude oil on our Adam Concession's sales volumes. 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").

For the year to date, our royalties of $8.0 million decreased relative to the same period of 2012. This reduction was the result of lower Canadian crude oil and natural gas liquids revenue. The year to date increase in Canadian royalties on a boe basis, as compared to the same period in 2012, resulted from higher natural gas pricing.

Production and Operating Expense

Three months ended June 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating expense	**$ 12,655**	**$ 4,725**	**$ 17,380**	$ 14,647	$ 1,642	$ 16,289
Less:						
Processing & gathering revenues	**(1,308)**	**-**	**(1,308)**	(2,156)	-	(2,156)
Net production & operating expense[1]	**$ 11,348**	**$ 4,725**	**$ 16,072**	$ 12,491	$ 1,642	$ 14,133
Per sales net production & operating expenses *($/boe)*[1]	**$ 15.55**	**$ 23.74**	**$ 17.31**	$ 13.79	$ 22.95	$ 14.46
Per sales production & operating expenses *($/boe)*	**$ 17.34**	**$ 23.74**	**$ 18.71**	$ 16.17	$ 22.95	$ 16.67

Six months ended June 30			2013			2012
($ thousands, except where noted)	Canada	Tunisia	Total	Canada	Tunisia	Total
Production & operating expense	**$ 27,675**	**$ 7,984**	**$ 35,659**	$ 35,278	$ 5,542	$ 40,820
Less:						
Processing & gathering revenues	**(4,707)**	**-**	**(4,707)**	(4,810)	-	(4,810)
Net production & operating expense[1]	**$ 22,968**	**$ 7,984**	**$ 30,952**	$ 30,468	$ 5,542	$ 36,010
Per sales net production & operating expenses *($/boe)*[1]	**$ 15.24**	**$ 24.75**	**$ 16.92**	$ 15.29	$ 24.71	$ 16.24
Per sales production & operating expenses *($/boe)*	**$ 18.37**	**$ 24.75**	**$ 19.49**	$ 17.70	$ 24.71	$ 18.41

(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.

Despite a decrease in sales volumes during the second quarter, the production and operating expense of $17.4 million increased relative to the same period of 2012. This increase resulted from higher Tunisian sales volumes which are more costly to produce, on a boe basis, during this early stage of development. Inversely, for the year to date, production and operating expense of $35.7 million decreased relative to the same period of 2012 because of lower Canadian sales volumes.

In Canada, the $12.7 million and $27.7 million of production and operating expense for the second quarter and year to date decreased, respectively, relative to the same periods of 2012. These decreases resulted from lower sales volumes due to Canadian property dispositions during 2012 and 2013 in addition to non-operated and third party facility downtime. We continue to focus on improving our Canadian operating cost structure which has resulted in various process changes and cost saving initiatives.

In Tunisia, the increased sales volumes in the current reporting periods as compared to the same periods of 2012 resulted in higher reported operating costs. During the second quarter, as compared to the same period of 2012, the sales volumes from our lower production cost Adam Concession, on a boe basis, represented a larger proportion of our Tunisian segment's sales volumes, causing the US dollar denominated Tunisian operating costs per boe to decrease. However, this US dollar operating costs per boe decrease was offset by the strengthening of the US dollar, resulting in an overall increase in this Canadian dollar reported measure.

Our Tunisian operating costs associated with the inventoried crude oil as at June 30, 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 third quarter of 2013 when we sell the associated crude oil volumes.

The decrease in processing and gathering revenue during the second quarter resulted from the dispositions during 2012 and 2013 of some of our facilities and pipelines, as compared to the same period of 2012. This effect, on a year to date basis, was offset by increased third party volumes through our existing facilities and pipelines as reported during the first quarter of 2013.

General & Administrative ("G&A") Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2013**	2012	**2013**	2012
G&A expense	**$ 2,828**	$ 4,276	**$ 5,550**	$ 8,601
Add back/(deduct):				
Share-based compensation	**(290)**	(884)	**(725)**	(1,711)
Amortization of deferred lease liability	**264**	264	**528**	528
Cash G&A expense(1)	**$ 2,802**	$ 3,656	**$ 5,353**	$ 7,418
Per sales *($/boe)*	**$ 3.02**	$ 3.74	**$ 2.92**	$ 3.35

(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 periods' cash cost of G&A expenses.

G&A expense for the second quarter and year to date decreased as compared to the same periods 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. Lower share-based compensation resulted from an increase in recoveries of previously reported share-based compensation on forfeited unvested options and less fair value remaining to expense on unvested outstanding options. These were partially offset by an increase in granted options with a higher associated fair value.

Corporate Netbacks

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

Three months ended June 30			2013			2012
Per sales *($/boe)*	Canada[2]	Tunisia	Total	Canada[2]	Tunisia	Total
Realized sales price	**$ 40.02**	**$ 101.19**	**$ 53.13**	$ 28.03	$ 109.13	$ 33.97
Less:						
Royalties	**(5.23)**	**(3.61)**	**(4.88)**	(3.32)	(2.95)	(3.29)
Net production expense [3]	**(15.55)**	**(23.74)**	**(17.31)**	(13.79)	(22.95)	(14.46)
Cash G&A [4]	**(2.76)**	**(3.95)**	**(3.02)**	(3.23)	(10.19)	(3.74)
Corporate netback [1]	**$ 16.48**	**$ 69.89**	**$ 27.92**	$ 7.69	$ 73.04	$ 12.48

Six months ended June 30			2013			2012
Per sales *($/boe)*	Canada[2]	Tunisia	Total	Canada[2]	Tunisia	Total
Realized sales price	**$ 37.85**	**$ 103.78**	**$ 49.47**	$ 30.56	$ 116.10	$ 39.22
Less:						
Royalties	**(4.64)**	**(2.98)**	**(4.35)**	(3.86)	(3.40)	(3.81)
Net production expense [3]	**(15.24)**	**(24.75)**	**(16.92)**	(15.29)	(24.71)	(16.24)
Cash G&A [4]	**(2.93)**	**(2.95)**	**(2.92)**	(3.31)	(3.66)	(3.35)
Corporate netback [1]	**$ 15.04**	**$ 73.10**	**$ 25.28**	$ 8.10	$ 84.33	$ 15.82

(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 current reporting periods, our corporate netbacks increased 124% and 60%, respectively, as compared to the same periods of 2012. This improvement resulted from a higher proportion of these netbacks being contributed from the relatively higher Tunisian netbacks, as well as the higher Canadian corporate netbacks. The current reporting periods' corporate netbacks of $27.92 and $25.28 per boe were 53% and 51% of the average realized sales price, and were significant improvements over the same periods in 2012.

The increase in the Canadian corporate netbacks resulted from increases, on a boe basis, in Canadian realized crude oil and natural gas pricing and lower cash G&A costs as partially offset by lower Canadian realized natural gas liquids pricing and higher royalties. In addition, the second quarter Canadian corporate netback was affected by a higher net production expense per boe. The Canadian corporate netbacks includes cash G&A costs related to our corporate office of $1.92 and $1.90 per boe for the current reporting periods.

Our Tunisian segment's netbacks for the current reporting periods, relative to the same periods of 2012, decreased due to lower crude oil and natural gas prices. In addition, our Tunisian segment's second quarter netback decreased, on a boe basis, because of higher royalties and production expense. This higher royalties expense, on a boe basis, resulted from a higher proportion of sales from our royalty paying Adam Concession. The higher per boe production expense resulted from the strengthening of the US dollar, despite a decrease in the US dollar denominated production expense. Targeted improvements in our trucking costs should further decrease our production expense on a boe basis by the end of this year. Tunisian production and operating costs on a boe basis are then anticipated to remain at that level until the start up of our gathering and processing facility, the timing of which is still to be determined. This facility will have a lower production cost per boe compared to the single well batteries equipped with relatively expensive rental equipment that are currently in use.

Exploration and Evaluation Expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	2013	2012	2013	2012
Canada	**$ 457**	$ 999	**$ 3,555**	$ 2,053
Tunisia	**3,136**	2,313	**4,537**	4,448
Total	**$ 3,593**	$ 3,312	**$ 8,092**	$ 6,501

Exploration and evaluation expense for the current reporting periods of $3.6 million and $8.1 million, respectively, were higher compared to those reported during the same periods of 2012.

During the current reporting periods, the El Bell 1 ("EB-1") exploration well located on our onshore Sud Remada Permit was drilled and despite encountering hydrocarbons in the target Ordovician zone, following further testing was suspended after being evaluated as non-commercial. Because of this, drilling costs as at June 30, 2013 of $3.2 million, including a $0.1 million estimated decommissioning charge, were directly charged to exploration and evaluation expense.

During the year to date, we determined that a Canadian exploration well that was drilled and reported within exploration and evaluation assets in 2012, was unsuccessful for petroleum or natural gas reserves. Costs incurred on this Canadian exploratory well of $1.4 million were expensed during the year to date through exploration and evaluation expense.

The remaining $3.5 million of costs were mostly comprised of Canadian and Tunisian exploratory lease rental and geological and geophysical costs for the current reporting periods as directly charged to exploration and evaluation expense. We anticipate that seismic data aquired on our Tunisian Borj El Khadra ("BEK") on shore exploration permit will be evaluated during the third quarter of 2013 and potential exploration drilling locations identified shortly thereafter.

Risk Management Contract (Gains) Losses

	Three months ended June 30		Three months ended June 30	
($ thousands)	**2013**	2012	**2013**	2012
Realized loss (gain) on commodity contracts	**$ 63**	$ (406)	**$ 74**	$ (141)
Unrealized gain on commodity contracts and swap option	**(1,149)**	(13,002)	**(556)**	(6,085)
Total	**$ (1,086)**	$ (13,408)	**$ (482)**	$ (6,226)

We use commodity price risk management contracts to reduce our exposure to fluctuations in commodity prices. As at June 30, 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 June 30, 2012, the swap option's reported fair value was determined using a Black-Scholes model. This model included the inputs of a forward WTI price and expected WTI price volatility over the remaining term of the swap option. This swap option was settled during 2012 for a nominal amount.

The net settlement of the commodity price contracts for the current reporting periods resulted in realized losses as compared to our realized gains in the same periods of 2012.

Net Financing Expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2013**	2012	**2013**	2012
Interest on bank debt	**$ 1,357**	$ 1,064	**$ 2,632**	$ 2,405
Interest earned on bank deposits	**(29)**	(3)	**(328)**	(5)
Finance charges and fees	**77**	425	**149**	582
Amortization of deferred financing costs	**185**	-	**246**	-
Accretion of decommissioning obligation	**676**	652	**1,380**	1,496
Total	**$ 2,266**	$ 2,138	**$ 4,079**	$ 4,478

The increase in our interest on bank debt for the current reporting periods, as compared to the same periods of 2012, stemmed from higher average interest rates resulting from the terms of a new Canadian facility agreement that was entered into on December 11, 2012. This resulted in an increase in our current reporting periods' effective interest rate to approximately 5.2%, from 4.4% for the same periods of 2012. Partially offsetting this effective interest rate increase was a decrease in each current reporting period's average outstanding long-term debt.

An increase in the amortization of deferred financing fees during the current reporting periods, as compared to the same periods of 2012, mostly resulted from our International Credit Facility signed during the first quarter of 2013 and discussed under the "Credit Facilities" section. For the current year to date we have incurred $2.6 million in deferred financing fees.

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

	Three months ended June 30		Six months ended June 30	
($ thousands, except per unit amounts)	2013	2012	2013	2012
Canada	**$ 13,462**	$ 18,331	**$ 27,230**	$ 39,905
Tunisia	**6,206**	2,072	**10,407**	6,541
Total	**$ 19,668**	$ 20,403	**$ 37,637**	$ 46,446
Per sales *($/boe)*	**$ 21.18**	$ 20.88	**$ 20.58**	$ 20.95

DD&A expense for the current reporting periods decreased from the same periods 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 in addition to lower Canadian sales volumes. The effect of the lower carrying amount of our Canadian development and production assets also decreased the depletion charge on a boe basis for the current year to date reporting period, as compared to the same period in 2012. In addition, an increase in the estimated time period to amortize our undeveloped acreage costs further decreased the DD&A expense. Depletion costs associated with inventoried Tunisian crude oil volumes are included in our inventory carrying amount and are reported as depletion in a subsequent quarter when the crude oil is loaded onto shipping tankers.

Impairment of Development & Production Assets

At June 30, 2012, we recognized an impairment charge of $26.5 million. At June 30, 2013, we determined that there were no indications of impairment that would warrant a test for impairment.

Gains on Disposition of Properties

During the year to date, we completed the sale of several petroleum and natural gas properties mostly located throughout Alberta, Canada. Aggregate net proceeds were $16.4 million (2012 - $71.8 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 $11.7 million for the year to date as compared to $4.9 million for the same period of 2012.

Income Tax Expense (Recovery)

	Three months ended June 30		Six months ended June 30	
($ thousands)	2013	2012	2013	2012
Current income tax expense	**$ 2,309**	$ 583	**$ 2,939**	$ 2,315
Deferred income tax expense (recovery)	**530**	(301)	**(140)**	(378)
Total	**$ 2,839**	$ 282	**$ 2,799**	$ 1,937

Current income taxes, relating to our Adam Concession located onshore Tunisia, increased in the current reporting periods as compared to the same periods of 2012. These increases resulted from higher crude oil and natural gas sales volumes and a lower tax base that shelters taxable income from this Concession.

The deferred income tax recovery of $0.1 million decreased for the current reporting year to date period as compared to the same period of 2012. This decrease was due to recent periods' lower capital expenditures on our taxable Adam Concession. The current year to date deferred income tax recovery was also affected by 3D seismic study costs on our BEK exploratory permit, located onshore Tunisia. These costs partially 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 June 30		Six months ended June 30	
($ thousands, except per share amounts)	2013	2012	2013	2012
Net income (loss)	**$ 3,990**	$ (24,812)	**$ 8,490**	$ (41,903)
Per share - basic and diluted *($/share)*	**0.02**	(0.12)	**0.04**	(0.20)
Comprehensive income (loss)	**$ 8,589**	$ (23,247)	**$ 15,233**	$ (41,892)
Per share - basic and diluted *($/share)*	**0.04**	(0.11)	**0.07**	(0.20)
Weighted average shares outstanding - basic and diluted *(thousands)*	**214,188**	214,188	**214,188**	214,188

Our net income of $4.0 million and $8.5 million for the current reporting periods increased, respectively, relative to the net losses in the same periods of 2012. These increases were mostly due to higher Canadian realized petroleum and natural gas prices, higher Tunisian sales volumes, lower expenses, and higher gains on property dispositions as well as the absence of any impairment of our Canadian development and production assets as compared to the recognized impairment of $26.5 million during the comparable periods of 2012. In addition, the current year to date reporting period benefited from the realization of the disposition proceeds on a joint arrangement (see "Joint Arrangement").

Comprehensive income, which includes our net income and a foreign currency translation gain, increased for the current reporting periods as compared to losses in the same periods in 2012. These increases in comprehensive income were consistent with the increases in our net income plus foreign currency translation gains on marking-to-market our Tunisian US dollar denominated net assets to the strengthening 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 and test resource play concepts in Canada. In Tunisia we are accelerating the development of our discoveries and existing fields.

Cash flow for the year to date, in addition to proceeds from the disposition of Canadian non-core properties and opening cash reserves, financed the investment in capital, exploration and evaluation expenditures and an increase in non-cash working capital. During the year to date, we completed the sale of Canadian non-core properties with associated volumes totalling approximately 470 boe per day.

Cash Flow

	Three months ended June 30		Six months ended June 30	
($ thousands, except per share amounts)	2013	2012	2013	2012
Cash flow from operations	**$ 21,850**	$ 8,393	**$ 25,742**	$ 20,771
Add back (deduct):				
Change in operating non-cash working capital	**(256)**	949	**13,491**	6,221
Deferred disposition proceeds	**-**	-	**3,051**	-
Decommissioning obligation expenditures	**585**	488	**1,413**	2,012
Cash flow[(1)]	**$ 22,179**	$ 9,830	**$ 43,697**	$ 29,004
Per share - basic and diluted[(1)]	**$ 0.10**	$ 0.05	**$ 0.20**	$ 0.14
Per sales *($/boe)*[(1)]	**$ 23.88**	$ 10.06	**$ 23.89**	$ 13.08

(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.

Cash flow of $22.2 million and $43.7 million for the current reporting periods, increased, respectively, as compared to the same periods of 2012. These increases were due to both higher Tunisian sales volumes and Canadian petroleum and natural gas prices. In addition, the current year to date cash flow increased because of lower cash expenses and a one-time termination of the NZOG Hammamet Pty. Ltd ("NZOG") optional right (see "Joint Arrangement").

On a pro forma basis, assuming that sales volumes were consistent with production and that the Tunisian crude oil inventory held at June 30, 2013 was sold at the subsequently received price of US$106.04 per barrel, the cash flow for the second quarter would have decreased to $20.8 million and increased to $47.6 million for the year to date.

Credit Facilities

	June 30	December 31
($ thousands)	2013	2012
Long-term debt	**$ 86,695**	$ 89,137
Less:		
Working capital excluding mark-to-market derivative contracts	**(20,355)**	(16,754)
Net debt[(1)]	**$ 66,340**	$ 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 $66.3 million as at June 30, 2013, decreased relative to $72.4 million as at December 31, 2012 mainly due to a $3.7 million increase in working capital excluding marked-to-market derivative contracts. In addition, an increase in deferred financing costs, related to signing a new international credit facility secured by our Tunisian assets and extending the revolving period of our existing Canadian credit facility, 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. During the current reporting periods, we extended the revolving period through to June 26, 2014. 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 26, 2015. 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. As at June 30, 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 $0.4 million remained at June 30, 2013 ($0.4 million at December 31, 2012) and will be amortized through to the existing term of this facility.

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. As at June 30, 2013, we were in compliance with this covenant and anticipate being in compliance through to the existing term of this facility.

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. Interest payable on drawings from the International Revolving Credit Facility will vary based on a prescribed margin plus U.S. LIBOR. As at June 30, 2013, we had no outstanding drawings against the International Credit Facility. Unamortized deferred financing costs of approximately $2.4 million remained at June 30, 2013 and will be amortized through to the expiry of the facility in March 2018.

Subsequent to June 30, 2013 and prior to the date of this report, we made a debt repayment of $5.0 million bringing our total outstanding debt draws to $84.5 million and increasing our total available credit to approximately $77.0 million.

Capital Expenditures

Three months ended June 30				**2013**				**2012**
($ thousands)	**Canada**	**Tunisia**	**Corporate**	**Total**	**Canada**	**Tunisia**	**Corporate**	**Total**
Land and lease	**$ 229**	**$ -**	**$ -**	**$ 229**	$ 188	$ -	$ -	$ 188
Drilling and completions	**4,226**	**11,266**	**-**	**15,492**	1,499	6,807	-	8,306
Facilities and equipment	**777**	**4,811**	**-**	**5,588**	2,182	1,317	-	3,499
Field expenditures	**5,232**	**16,077**	**-**	**21,309**	3,869	8,124	-	11,993
Capitalized G&A	**272**	**1,428**	**-**	**1,700**	463	552	-	1,015
Furniture and equipment	**-**	**-**	**50**	**50**	-	-	-	-
Property acquisitions	**-**	**-**	**-**	**-**	75	-	-	75
Total	**$ 5,504**	**$ 17,505**	**$ 50**	**$ 23,059**	$ 4,407	$ 8,676	$ -	$ 13,083
Proceeds from dispositions	**$ 3,360**	**$ -**	**$ -**	**$ 3,360**	$ 17,035	$ -	$ -	$ 17,035

Six months ended June 30				**2013**				**2012**
($ thousands)	**Canada**	**Tunisia**	**Corporate**	**Total**	**Canada**	**Tunisia**	**Corporate**	**Total**
Land and lease	**$ 2,762**	**$ -**	**$ -**	**$ 2,762**	$ 577	$ -	$ -	$ 577
Drilling and completions	**14,799**	**15,262**	**-**	**30,061**	11,705	13,750	-	25,455
Facilities and equipment	**4,558**	**7,623**	**-**	**12,181**	5,251	3,093	-	8,344
Field expenditures	**22,119**	**22,885**	**-**	**45,004**	17,533	16,843	-	34,376
Capitalized G&A	**567**	**2,454**	**-**	**3,021**	857	1,170	-	2,027
Furniture and equipment	**-**	**-**	**80**	**80**	-	-	51	51
Property acquisitions	**-**	**-**	**-**	**-**	75	-	-	75
Total	**$ 22,686**	**$ 25,339**	**$ 80**	**$ 48,105**	$ 18,465	$ 18,013	$ 51	$ 36,529
Proceeds from dispositions	**$ 16,420**	**$ -**	**$ -**	**$ 16,420**	$ 71,775	$ -	$ -	$ 71,775

Wells Drilled

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

Three months ended June 30, 2013	Tunisia		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Exploration oil wells	-	**-**	-	**-**	-	**-**
Development oil wells	3.00	**1.77**	-	**-**	3.00	**1.77**
Dry wells	1.00	**0.86**	-	**-**	1.00	**0.86**
Total	4.00	**2.63**	-	**-**	4.00	**2.63**

Six months ended June 30, 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	**1.77**	3.00	**1.37**	6.00	**3.14**
Dry wells	1.00	**0.86**	-	**-**	1.00	**0.86**
Total	4.00	**2.63**	7.00	**3.61**	11.00	**6.24**

Canada Capital Expenditures

The second quarter was operationally quiet in Canada, due to spring break up conditions in the field. No wells were rig released during the quarter; however, one (1.0 net) existing well in the Grande Prairie core area was completed for natural gas production from an uphole zone, and one (1.0 net) Grande Prairie area horizontal well targeting Dunvegan oil was spud in late June.

The Kaybob area in West Central Alberta contains a developing Montney oil prospect. Our two (0.75 net) existing Montney horizontal oil wells were both brought on production in April 2013. The initial production rate from each well was encouraging, but the run time of these wells has been somewhat sporadic due to third party facility issues. During June 2013, the two wells were producing at a combined gross rate of about 500 boe per day (60% liquids), when on for full days. We will continue to closely monitor the performance of these and offsetting competitor wells prior to committing to more activity later in 2013 and in 2014. 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. We have surveyed two surface locations which could be used to drill up to four (3.0 net) operated horizontal wells this winter.

In the Grande Prairie core area, the bulk of our recent activity has been focused on oil in the Doe Creek and Dunvegan zones, with projects ongoing at Karr, Albright, Beaverlodge, Sinclair, Wapiti, and Grovedale. At Karr, all five (1.86 net) previously drilled horizontal Dunvegan oil wells are now on production, with three (1.13 net) more horizontal wells expected to be drilled by the end of 2013, and up to 25 additional locations identified. Production rates at this location continue to meet or exceed management's expectations.

We began drilling three (3.0 net) Dunvegan horizontal wells on the recently acquired Albright and Beaverlodge properties late in the second quarter. These are in addition to the three (1.5 net) horizontal oil wells drilled and brought on production during the first quarter of 2013. The new wells are all expected to be completed and on stream by the end of the third quarter of 2013. One (1.0 net) existing vertical oil well that was producing a minimal amount of crude oil was also re-completed in an uphole natural gas zone during the second quarter, adding nearly 100 boe per day of production. We have identified over 30 horizontal oil drilling locations on existing acreages, along with significant optimization and waterflood upside on these properties. We are also actively pursuing additional exploration and acquisition opportunities in the area.

Additional opportunities currently budgeted for the remainder of 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 natural gas in NE British Columbia at Birley.

Tunisia Capital Expenditures

Our BBT Concession's capital activity in the second quarter included the drilling and completion of the TT12 horizontal well and the drilling of the TT21 vertical well. The TT12 horizontal well was drilled and completed with a six stage hydraulic fracture stimulation. Initial production shows high water cuts and lower than expected oil rates. The well will undergo an intervention to attempt to reduce the water production in the third quarter of 2013. The TT21 well was drilled as a vertical Ordovician development well and will be completed and brought on production in the third quarter of 2013.

During the second quarter, artificial lift in the form of jet pumps was installed on the BBT TT10 horizontal well, TT11 horizontal well and TT2 vertical well. The jet pumps allowed the TT10 and TT2 wells to recommence production since they were shut-in during the first quarter of 2013 and the fourth quarter of 2012, respectively, and increased the production of the TT11 well which was previously unable to continuously flow on natural production. Subsequent to the end of the quarter, TT20 was drilled three kilometers west of the closest producer and was cased having encountered the thickest lower Jeffera pay section (24 meters) thus far at original reservoir pressures. We are finalizing drilling plans with ETAP and still expect to drill five to seven wells at BBT during the remainder of 2013, after completion operations on the BBT TT20 and TT21 wells, and the recompletion of the TT4 well are finished.

On the non-operated Adam Concession and BEK Permit, a sidetrack was drilled on the Karma-2 well. The Karma-2 side track well is anticipated to come on production in the third quarter.

The Gulf of Hammamet two year work program includes a commitment well to be drilled no later than September 2015. We are evaluating the potential of several prospective leads with the objective of recommending a preferred well location to partners by year end 2013. Development and export options for the Fushia volatile oil discovery will also be evaluated over the remainder of 2013.

Although all work commitments are current on Cosmos, following termination of the NZOG farm-in agreement, we agreed with the Tunisian authorities on a work program to better delineate some near field appraisal opportunities with the objective of drilling an appraisal well. A successful well will materially improve the economics of the development. The initial evaluation of the project's economics is expected to be complete by this year end and depending on the interpretation a well may be drilled either in late 2014 or early 2015.

Rationalization of Non-Core Properties

During the current year to date reporting period, we completed the sale of several non-core petroleum and natural gas properties mostly located throughout Alberta, Canada, for aggregate net proceeds of $16.4 million, after including the final statements of adjustments for these and prior period dispositions. The non-core properties sold included Red Creek, portions of Gordondale, portions of Lochend, Edwand and Thonbury-Portage. Our production from these and the other sold properties was approximately 470 boe per day. The funds received for these dispositions were used to partially fund our capital program expenditures of $48.1 million.

Joint Arrangement

On March 19, 2013, both we and NZOG acknowledged that each of us had given a negative final investment decision ("FID") as defined under the terms of our 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 the termination of this 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) and losses on the condensed consolidated statements of operations and comprehensive income (loss) during the year to date 2013.

Decommissioning Obligation

At June 30, 2013, we have decommissioning obligations of $102.7 million (December 31, 2012 - $110.5 million) for the future abandonment and reclamation of our properties. As at June 30, 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 $8.7 million of obligations in addition to $1.4 million of abandonment and reclamation expenditures.

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 in 2012. During the current year to date reporting period, additions to the decommissioning liability of $0.8 million were mostly related to the current period's drilling activities (2012 - $0.5 million).

Outstanding Share Data

Authorized:

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

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

	June 30 2013	December 31 2012
Common shares outstanding	**214,187,681**	214,187,681
Share options	**14,607,501**	13,860,866
Share purchase warrants	**-**	1,279,000
Fully diluted common shares	**228,795,182**	229,327,547
Weighted average common shares - basic and diluted	**214,187,681**	214,187,681

As at August 13, 2013, we had issued 214,187,681 common shares and had 14,332,982 outstanding options.

On June 30, 2013, 1,279,000 share purchase warrants with an exercise price of $3.25 per common share expired unexercised.

Commodity Price Risk Management Contracts and Swap Option

To mitigate commodity price risk, 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. Our commodity price risk management activities are limited by adherence to a Board of Directors approved hedging policy which determines which comodities can be hedged, the maximum notional volume of hedged production, the reference indexed price and terms of hedges.

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 and to a lesser extent the foreign exchange impact of the translation from the US to Canadian dollar. 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.

As at June 30, 2013, we had the following commodity price contracts with an estimated fair value of $0.6 million:

Indexed Price	Notional Volumes	Company's Received Price	Remaining period
AECO	7,000 GJ/d	$3.20/GJ	July 1, 2013 to December 31, 2013
AECO	3,000 GJ/d	$3.40/GJ	July 1, 2013 to October 31, 2013
Brent	500 bbl/d	$95.00 US/bbl to $115.50 US/bbl	July 1, 2013 to December 31, 2013

Outlook

We are revising our guidance for 2013 to reflect reduced capital investment in Tunisia due to operational delays on the BBT program coupled with the switch to vertical wells that have an estimated lower initial production rates but projected greater economic rate of return from the higher initial rate horizontal wells contemplated in the original 2013 program. Updated guidance is provided below:

	Revised Guidance			Original Guidance		
($ millions, except boe/d)	Consolidated	International	Canada	Consolidated	International	Canada
Production *(boe/d)*	9,350 – 10,000	2,000 – 2,250	7,350 – 7,750	9,500 – 10,200	2,150 – 2,450	7,350 – 7,750
Cash flow	$85 – $90	$45 – $48	$40 – $42	$95 – $100	$55 – $58	$40 – $42
Capital expenditures	$95 – $100	$51 – $53	$44 – $47	$102 – $107	$58 – $60	$44 – $47
Net debt	$60 – $65	-	$60 – $65	$60 – $65	-	$60 – $65
Debt facility	$161.5	US$46.5	$115	$115	-	$115

Our focus for the balance of 2013 will be on increasing our oil weighting in Western Canada with a capital program directed solely at oil opportunities. We will continue to develop our lower risk Dunvegan and Doe Creek properties while moving our Montney opportunities closer to drill ready stage for 2014. In Tunisia, we will continue to appraise and develop our BBT Concession along with interpreting newly acquired 3-D seismic data over the offshore Cosmos Concession to determine the optimal location for a future appraisal well that would serve to establish additional reserves and justify field development. Our balance sheet remains strong and our per share profitability continues to improve quarterly and with that, management anticipates continuing to provide shareholders with positive updates throughout 2013.

Quarterly Information

Summarized information by quarter for the two years ended June 30, 2013, appears below:

	Jun. 30 2013	Mar. 31 2013	Dec. 31 2012	Sept. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011	Sept. 30 2011
OPERATIONS								
Production								
Oil *(bbl/d)*	**3,298**	3,565	4,035	3,516	3,195	3,819	4,206	3,705
Natural gas liquids *(bbl/d)*	**874**	1,005	1,003	1,141	1,122	1,202	1,591	1,343
Natural gas *(mcf/d)*	**34,458**	37,736	39,585	43,839	43,387	51,445	55,927	56,364
Average daily production *(boe/d)*	**9,916**	10,860	11,636	11,964	11,548	13,596	15,119	14,443
Sales								
Oil *(bbl/d)*	**3,588**	2,710	4,264	3,929	2,385	3,846	4,282	3,775
Natural gas liquids *(bbl/d)*	**874**	1,005	1,003	1,141	1,122	1,202	1,591	1,343
Natural gas *(mcf/d)*	**34,458**	37,736	39,584	43,839	43,387	51,445	55,927	56,364
Average daily sales *(boe/d)*	**10,205**	10,006	11,865	12,377	10,738	13,623	15,195	14,514
Sales Prices								
Average oil price *($/bbl)*	**$ 98.07**	$ 95.03	$ 97.72	$ 95.61	$ 89.11	$ 101.06	$ 97.11	$ 94.19
Average natural gas liquids price *($/bbl)*	**$ 55.06**	$ 58.85	$ 57.71	$ 56.42	$ 55.46	$ 70.66	$ 71.23	$ 67.15
Average natural gas price *($/mcf)*	**$ 4.13**	$ 3.72	$ 3.39	$ 2.57	$ 2.08	$ 2.27	$ 3.31	$ 3.84
Corporate Netbacks(1)								
Average commodity pricing *($/boe)*	**$ 53.13**	$ 45.70	$ 51.30	$ 44.67	$ 33.97	$ 43.35	$ 47.00	$ 45.63
Royalties *($/boe)*	**$ (4.88)**	$ (3.79)	$ (0.64)	$ (2.50)	$ (3.29)	$ (4.22)	$ (6.03)	$ (5.24)
Net production expenses *($/boe)*(1)	**$ (17.31)**	$ (16.52)	$ (18.98)	$ (18.38)	$ (14.46)	$ (17.65)	$ (17.75)	$ (20.25)
Cash G&A *($/boe)*(1)	**$ (3.02)**	$ (2.83)	$ (4.48)	$ (2.54)	$ (3.74)	$ (3.03)	$ (5.13)	$ (1.80)
Corporate netbacks *($/boe)*(1)	**$ 27.92**	$ 22.56	$ 27.20	$ 21.25	$ 12.48	$ 18.45	$ 18.10	$ 18.34
Wells Drilled (net)								
Oil	**1.77**	3.61	2.96	1.11	0.86	3.16	6.12	7.45
Gas	**-**	-	-	-	-	1.00	1.02	0.65
Dry	**0.86**	-	-	-	0.86	0.10	-	-
Total wells drilled (net)	**2.63**	3.61	2.96	1.11	1.72	4.26	7.14	8.10
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties(2)	**$ 44,805**	$ 37,740	$ 55,303	$ 48,012	$ 29,979	$ 48,509	$ 57,274	$ 53,920
Cash flow(1)(2)	**$ 22,179**	$ 21,518	$ 28,757	$ 20,935	$ 9,830	$ 19,174	$ 23,950	$ 22,114
Per share - basic and diluted *($/share)*	**$ 0.10**	$ 0.10	$ 0.13	$ 0.10	$ 0.05	$ 0.09	$ 0.11	$ 0.10
Net income (loss)(2)(3)	**$ 3,990**	$ 4,500	$ (36,708)	$ (12,417)	$ (24,812)	$ (17,091)	$ (58,077)	$ (3,543)
Per share - basic and diluted *($/share)*	**$ 0.02**	$ 0.02	$ (0.17)	$ (0.06)	$ (0.12)	$ (0.08)	$ (0.27)	$ (0.02)
Capital expenditures	**$ 23,059**	$ 25,046	$ 50,456	$ 22,674	$ 13,083	$ 23,446	$ 26,343	$ 30,687
Net debt(1)	**$ 66,340**	$ 64,440	$ 72,383	$ 80,428	$ 77,092	$ 89,182	$ 134,900	$ 151,014
Total assets	**$ 621,143**	$ 617,459	$ 622,476	$ 628,542	$ 637,238	$ 692,023	$ 745,403	$ 870,908
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 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 60,000 barrels was not sold at June 30, 2012, March 31, 2013, and June 30, 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 second 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 effect of the Brent, Edmonton par and AECO benchmarks which generally trended down until the second quarter of 2012 and have since trended upwards, petroleum and natural gas revenues, net of royalties, have recovered from the effects of the non-core property disposition program. This, in turn, has generated sufficient cash flow to reduce our net debt and has allowed us to avoid having to access the equity markets.

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 Annual Information Form for the year ended December 31, 2012 ("AIF") and below 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 and below 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 materially adversely impacted.

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

Tunisian Political and Security Risk Update

The political stability and resulting security situation in Tunisia have taken several steps back recently after a four to five month period of relative calm, which had been viewed as a signal of progress. The majority of the timing and motivation of the acts of civil disobedience are politically motivated, perpetrated by parties intent on de-stabilizing the Tunisian political process and not directed towards us or foreign investment in Tunisia. In response to the destabilized conditions, we have increased our security preparedness and threat assessment protocols. The existing situtation serves to increase the logistical complexity and security related costs of our operations. We expect that the current instability will continue during the balance of the year as we approach the promised elections. We will continue to carefully monitor the situation and manage for the long-term success of our Tunisian business while maintaining a priority on the immediate security of our personnel and stakeholders. The destabilized conditions in Tunisia may result in unforeseen delays in the execution of our operational program.

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 June 30, 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 June 30, 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, projected well costs; the operations to be conducted, wells to be drilled and/or completed and the timing thereof on certain of Chinook's Canadian and Tunisian 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; 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 anticipated 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.