Q3

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 nine months ended September 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 nine months ended September 30, 2014 and 2013 and our audited 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 November 13, 2014.

The term "third quarter" and "year to date" or similar terms are used throughout this document and refer to the three and nine months ended September 30, 2014, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three and nine months ended September 30, 2014, in this respective order. The term "same period(s) of 2013" or similar terms are used throughout this document and refer to either the three or (and) nine months ended September 30, 2013, in this respective order, 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

Our unaudited condensed consolidated financial statements and comparative information for the three and nine months ended September 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. Our unaudited 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 (surplus), 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 petroleum and natural gas production company focused on development and exploration opportunities in western Canada. Our operations combine multi-zone conventional production and resource plays in our Western Canadian Sedimentary Basin producing properties and undeveloped land predominately located in northwestern Alberta and northeastern British Columbia. We are currently focused on the development of Montney liquids rich natural gas on our Birley/Umbach British Columbia properties, and Montney and Dunvegan light crude oil in Grande Prairie, Alberta.

We are incorporated under the laws of the Province of Alberta, Canada. Our common shares are listed and posted for trading 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.

Discontinued Operations

On August 19, 2014, our wholly-owned subsidiary, Storm Ventures International (BVI) Limited ("SVI (BVI)"), completed the sale, effective January 1, 2014, of all of the issued and outstanding shares of its wholly-owned subsidiary Storm Ventures International (Barbados) Limited ("SVI Barbados") in consideration for $140.5 million, including $15.8 million of working capital (the "Tunisian Disposition Transaction") pursuant to a share purchase and sale agreement dated June 14, 2014 (the "PSA"). SVI Barbados' wholly-owned subsidiary was Storm Sahara Limited ("SSL"). Combined, SVI Barbados and SSL held both of Chinook's Tunisian operating branches previously reported as the Tunisian segment in addition to a portion of the Corporate segment (combined the "Discontinued Tunisian Operations"). This disposition represented our complete exit from Tunisian crude oil and natural gas development and exploration.

The financial and operating results of the Discontinued Tunisian Operations for periods ended August 19, 2014, the date our control ceased, are separately presented in the "Discontinued Tunisian Operations" section of this MD&A.

Continuing Operations

Our western Canadian petroleum and natural gas producing and exploration assets, as previously reported as our Canadian segment, in addition to the remaining portion of our Corporate segment (combined the "Continuing Canadian Operations") are discussed in the "Continuing Canadian Operations" section of this MD&A. Unless specifically noted, all current and comparative reporting periods' operating and financial disclosures and discussion are in reference to our Continuing Canadian Operations.

Forward-Looking Information

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

Financial and Operating Highlights

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
CANADIAN CONTINUING OPERATIONS[2]				
Sales Volumes				
Crude Oil (bbl/d)	**1,823**	1,853	**2,057**	1,670
Natural gas liquids (boe/d)	**678**	753	**780**	877
Natural gas (mcf/d)	**29,028**	34,563	**29,320**	34,746
Average daily sales (boe/d)	**7,339**	8,367	**7,724**	8,338
Sales Prices				
Average oil price ($/bbl)	**$ 93.10**	$ 97.53	**$ 97.11**	$ 91.35
Average natural gas liquids price ($/boe)	**$ 64.71**	$ 62.36	**$ 70.73**	$ 58.61
Average natural gas price ($/mcf)	**$ 4.11**	$ 2.55	**$ 5.00**	$ 3.20
Netback[1]				
Average commodity pricing ($/boe)	**$ 45.37**	$ 37.76	**$ 52.00**	$ 37.82
Royalties ($/boe)	**$ (6.90)**	$ (3.53)	**$ (7.14)**	$ (4.27)
Net production expenses ($/boe)[1]	**$ (17.44)**	$ (16.42)	**$ (17.13)**	$ (15.64)
Cash G&A ($/boe)[1]	**$ (4.32)**	$ (1.71)	**$ (5.04)**	$ (2.51)
Netback ($/boe)[1]	**$ 16.71**	$ 16.10	**$ 22.69**	$ 15.40
Wells Drilled (net)				
Oil	**1.26**	3.00	**4.52**	6.61
Gas	**0.75**	-	**1.87**	-
Disposal/injection	**0.37**	-	**0.37**	-
Total wells drilled (net)	**2.38**	3.00	**6.76**	6.61
FINANCIAL *($ thousands, except per share amounts)*				
Petroleum & natural gas revenues, net of royalties	**$ 25,972**	$ 26,347	**$ 94,597**	$ 76,378
Cash flow[1]	**$ 9,693**	$ 12,213	**$ 42,089**	$ 32,328
Per share – basic and diluted ($/share)	**$ 0.05**	$ 0.06	**$ 0.20**	$ 0.15
Net income (loss) from continuing operations	**$ 3,696**	$ (316)	**$ 7,639**	$ 698
Per share – basic and diluted ($/share)	**$ 0.02**	$ –	**$ 0.04**	$ 0.01
Net income[3]	**$ 11,472**	$ 3,812	**$ 21,948**	$ 12,302
Per share – basic and diluted ($/share)	**$ 0.05**	$ 0.02	**$ 0.10**	$ 0.06
Capital expenditures	**$ 14,301**	$ 10,014	**$ 56,913**	$ 32,732
Net debt (surplus) [1][4]	**$ (35,870)**	$ 65,105	**$ (35,870)**	$ 65,105
Total assets[4]	**$ 472,241**	$ 593,192	**$ 472,241**	$ 593,192
Common Shares *(thousands)*				
Weighted average during period				
- basic	**214,895**	214,188	**214,439**	214,188
- diluted	**216,773**	214,188	**215,590**	214,188
Outstanding at period end	**215,079**	214,188	**215,079**	214,188

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

(2) See the "Continuing Canadian Operations" section of this MD&A.

(3) Includes the financial results from the Discontinued Tunisian Operations sold on August 19, 2014.

(4) The comparative periods include the Discontinued Tunisian Operations' assets or working capital excluding marked-to-market derivative contracts.

Continuing Canadian Operations

Petroleum and Natural Gas Sales Volumes

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Crude Oil (bbl/d)	**1,823**	1,853	**2,057**	1,670
Natural Gas Liquids (boe/d)	**678**	753	**780**	877
Natural Gas (mcf/d)	**29,028**	34,563	**29,320**	34,746
Total (boe/d)	**7,339**	8,367	**7,724**	8,338

Our third quarter crude oil sales volumes were relatively unchanged compared to the same quarter of 2013. During the third quarter we reported a one-time decrease of 100 barrels of oil per day ("bopd") related to adjustments on a well which had previously paid out. We also experienced lower crude oil production from our Karr and Knopcik properties which were impacted by third party plant turnarounds. Offsetting these decreases was production from wells drilled during our winter campaign as described below. Further increases are expected during the remainder of the year when our first horizontal Montney oil well (0.37 net) at Gold Creek, which was drilled during the first quarter of 2014 and saw final test rates of 500 bopd and six million cubic feet per day ("mmcfpd"), is expected to come on production.

Our year to date crude oil sales volumes increased by 387 bopd compared to the same period of 2013. This increase resulted from the wells we have now equipped and tied-in which were drilled during our previous winter campaign. This drilling campaign was focused on the development of our crude oil properties which included Albright, Karr and the aforementioned Montney prospect at Gold Creek.

Overall, our sales volumes decreased approximately 1,000 and 600 barrels of oil equivalent per day ("boepd") during the current reporting periods compared to the same periods of 2013. These decreases include approximately 230 and 700 boepd of production during the current reporting periods, associated with our non-core, natural gas focused, Canadian property dispositions. In addition, third party plant turnarounds at our Boundary Lake and Gilby properties, Whitecourt pipeline maintenance and natural reservoir production declines further decreased our sales volumes during the current reporting periods. Our first Birley/Umbach liquids rich well (0.75 net), which was drilled and completed during the first quarter of 2014, was only brought on restricted production mid-way through the third quarter after we completed necessary work at its associated facility. This well's gross restricted production was four mmcfpd and 100 barrels of field condensate per day (780 boepd, not including plant NGL recoveries) over its first 90 operating days. We plan on expanding our facility in this area to increase the throughput capacity from four mmcfpd to 35 mmcfpd by the second quarter of 2015 to accommodate production from the first of our two Birley/Umbach wells in addition to the 12 (11.1 net) 2015 budgeted wells. Finally, during the third quarter of 2013 we reported an increase of approximately three mmcfpd from third party plants re-allocating volumes to producers and adjustments from joint venture audits which was not realized during the current quarter.

Our drilling and completion expenditures for the third quarter of $10.6 million (same quarter of 2013 – $6.7 million) included two horizontal Dunvegan oil wells (1.26 net), a side track on an existing Dunvegan oil well (1.0 net) in addition to one (0.37 net) vertical water disposal well. These expenditures also included the drilling and successful completion of one (0.75 net) horizontal Montney gas well on our Birley/Umbach property, which is the second horizontal Montney well we have drilled there this year. Production from this third quarter drilling activity is anticipated to be onstream during the fourth quarter of 2014.

Petroleum and Natural Gas Revenues and Realized Pricing

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	**2014**	2013	**2014**	2013
Oil sales	**$ 15,614**	$ 16,626	**$ 54,541**	$ 41,659
$/bbl	**93.10**	97.53	**97.11**	91.35
Natural gas liquids sales	**$ 4,034**	$ 4,323	**$ 15,057**	$ 14,026
$/bbl	**64.71**	62.36	**70.73**	58.61
Natural gas sales	**$ 10,985**	$ 8,116	**$ 40,045**	$ 30,400
$/mcf	**4.11**	2.55	**5.00**	3.20
Petroleum and natural gas revenue	**$ 30,633**	$ 29,065	**$ 109,643**	$ 86,085
$/boe	**45.37**	37.76	**52.00**	37.82

Our petroleum and natural gas revenues of $30.6 million and $109.6 million increased during the current reporting periods compared to the same periods of 2013. These increases were caused by higher natural gas realized pricing offsetting this commodity's lower sales volumes. The increase for the year to date was also caused by both higher crude oil realized pricing and this commodity's sales volumes. This higher crude oil sales volume was the result of the focused development of our crude oil properties located near Grande Prairie, Alberta. This development, in conjunction with our 2013 disposition of predominately dry natural gas properties, increased our ratio of the relatively higher priced crude oil sales to 25% and 27% of total sales volumes during the current reporting periods compared to 22% and 20% in the same periods of 2013. During the current reporting periods, this increased ratio of crude oil sales, in addition to higher natural gas and natural gas liquids realized pricing, resulted in higher realized commodity pricing per boe. These higher prices reflected 20% and 37% increases in comparison to the same periods in 2013.

Benchmark Prices

	Three months ended September 30		Nine months ended September 30	
	2014	2013	**2014**	2013
Crude Oil				
Edmonton par ($/bbl)	**$ 97.71**	$ 104.74	**$ 100.53**	$ 95.18
Natural gas liquids				
WTI(1) ($US/bbl)	**$ 97.17**	$ 105.83	**$ 99.61**	$ 98.14
Natural gas				
AECO(2) ($/mcf)	**$ 4.08**	$ 2.47	**$ 4.88**	$ 3.10

(1) West Texas Intermediate

(2) Western Canadian Natural Gas reference price

Crude Oil Pricing

Our conventional crude oil production is sold at prices based on the Edmonton par benchmark postings adjusted for quality. This benchmark price decreased during the third quarter but increased during the year to date, as did our average realized crude oil prices, compared to the same periods of 2013. Our quality remained relatively consistent for the current reporting periods as compared to the same periods in 2013.

Natural Gas Liquids Pricing

Our 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 $64.71 and $70.73 per barrel for the current reporting periods 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 realized natural gas liquids price, during the current reporting periods, increased to 66% and 71%, respectively, from 60% and 62% in the same periods of 2013. These percentage increases resulted from a higher ratio of our mix being contributed from condensates with its associated higher realized price. This higher condensate ratio resulted from the third quarter's restricted production from our new Birley/Umbach well. Also, an increase in the year to date realized prices for ethane and propane in excess of the increase in the Edmonton par benchmark contributed to the higher natural gas liquids price and the increased ratios relative to this benchmark.

Natural Gas Pricing

Our realized natural gas price of $4.11 and $5.00 per mcf for the current reporting periods showed significant improvement from the $2.55 and $3.20 per mcf reported for the same periods of 2013. Although an equivalent boe of natural gas continues to sell at a significant discount relative to a barrel of oil, we realized a 61% and 56% increase in our natural gas prices during the current reporting periods compared to the same periods of 2013. Our realized natural gas price increases reflect the higher AECO benchmark prices. The increase in the first quarter's North American natural gas price was partially 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, this benchmark's pricing in the third quarter remained higher than in the comparative period.

Managing Commodity Price Risk

We mitigate a portion of our 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 September 30		Nine months ended September 30	
($ thousands, except where noted)	2014	2013	2014	2013
Royalties	**$ 4,661**	$ 2,718	**$ 15,046**	$ 9,707
Per sales ($/boe)	**$ 6.90**	$ 3.53	**$ 7.14**	$ 4.27
Percent of Revenues (%)	**15**	9	**14**	11

During the current reporting periods, our royalties of $4.7 million and $15.0 million increased relative to the same periods of 2013 due to higher petroleum and natural gas revenues. These higher revenues partially resulted from higher realized commodity pricing which also led to higher royalties on a boe basis. Adjustments to our gas cost allowance, oil wells coming off royalty holidays and these wells higher royalty rates also affected our royalties overall, on a boe basis and as a percentage of revenue.

Production and Operating Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	2014	2013	2014	2013
Production & operating	**$ 13,451**	$ 13,972	**$ 40,582**	$ 41,647
Less:				
Processing & gathering revenues	**(1,676)**	(1,330)	**(4,460)**	(6,037)
Net production & operating expense[(1)]	**$ 11,775**	$ 12,642	**$ 36,122**	$ 35,610
Per sales net production & operating expenses ($/boe)[(1)]	**$ 17.44**	$ 16.42	**$ 17.13**	$ 15.64
Per sales production & operating expenses ($/boe)	**$ 19.92**	$ 18.15	**$ 19.25**	$ 18.30

(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 $13.5 million and $40.6 million for the current reporting periods decreased compared to the same periods of 2013 as a result of lower sales volumes.

The increases in our production and operating costs on a boe basis 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 natural gas. Well start-up costs, plant turnarounds and pipeline repairs also increased our operating costs overall and on a per boe basis. Partially offsetting these increases were property dispositions during 2013 and to a lesser extent 2014, which caused lower natural gas and natural gas liquids sales volumes. These property dispositions included non-operated volumes for which we were charged higher operating costs on both an average and boe basis.

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 September 30		Nine months ended September 30	
($ thousands, except where noted)	2014	2013	2014	2013
G&A expense	**$ 3,274**	$ 2,117	**$ 10,822**	$ 6,713
Add back/(deduct):				
Share-based compensation	**(258)**	(370)	**(561)**	(1,095)
Provision for bad debts	**(100)**	(704)	**(165)**	(704)
Amortization of deferred lease liability	**-**	264	**528**	792
Cash G&A expense [(1)]	**$ 2,916**	$ 1,307	**$ 10,624**	$ 5,706
Per sales ($/boe)	**$ 4.32**	$ 1.71	**$ 5.04**	$ 2.51

(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 mostly due to lower reported overhead recoveries including those from our joint venture partners. The increase in the weighted average working interests of our current operated activities has lowered these partners' overhead recoveries. For the current reporting periods, in comparison to the same period in 2013, we also are recognizing the effect of increases for both salaries for our staff and consulting fees. In addition, year to date we incurred $1.1 million of incentive compensation. 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 calculation of our netback[1]:

	Three months ended September 30		Nine months ended September 30	
Per sales ($/boe)	**2014**	2013	**2014**	2013
Realized sales price	**$ 45.37**	$ 37.76	**$ 52.00**	$ 37.82
Less:				
Royalties	**(6.90)**	(3.53)	**(7.14)**	(4.27)
Net production expense[2]	**(17.44)**	(16.42)	**(17.13)**	(15.64)
Cash G&A[3]	**(4.32)**	(1.71)	**(5.04)**	(2.51)
Netback [1]	**$ 16.71**	$ 16.10	**$ 22.69**	$ 15.40

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

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

Our netbacks for the current reporting periods increased 4% and 47%, respectively, compared to the same periods of 2013. Contributing to the increases in our netback per boe were higher realized commodity prices and higher proportions of crude oil sales volumes relative to total sales volumes. These increases in the proportion of our 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 crude oil sales than we do on an equivalent boe of natural gas resulting in an increased netback.

During the current reporting periods, these netback increases, as compared to the same periods of 2013, were partially offset by increases, on a boe basis, of all associated production expenses. Although the increase in royalty expense per boe was contributed by higher realized pricing, there were additional charges such as gas cost allowance corrections and oil wells coming off of royalty holidays which further increased this expense. Over the short-term our production and operating costs are relatively fixed in nature. We also incurred field production and operating costs at Birley/Umbach despite being shut-in on our one well during a portion of the third quarter while we repaired this field's facility. When these production and operating costs during the current reporting periods are combined with lower sales volumes the result is an increase in this cost on a boe basis as compared to the same periods in 2013. Finally, we expect G&A on a boe basis to decrease as we anticipate that we are currently staffed to meet our projected 2015 sales volumes.

Exploration and Evaluation Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2014**	2013	**2014**	2013
Exploration and evaluation expenditures	**$ 478**	$ 276	**$ 1,063**	$ 2,631

Our exploration and evaluation expense decreased to $1.1 million compared to $2.6 million during the same period of 2013. For the current and comparative reporting periods, this expense was due to pre-licensing evaluation, exploratory lease rental and geological and geophysical costs. In addition, for the comparative 2013 year to date period the expense included the completion of an evaluation and the subsequent determination that an exploration well drilled during 2012, at a cost of $1.4 million, was unsuccessful for petroleum or natural gas reserves.

Risk Management Contract Losses (Gains)

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2014**	2013	**2014**	2013
Realized losses (gains) on derivative contracts	**$ 731**	$ (875)	**$ 3,601**	$ (805)
Unrealized gains on derivative contracts	**(2,440)**	(17)	**(363)**	(447)
Total	**$ (1,709)**	$ (892)	**$ 3,238**	$ (1,252)

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 the monthly average benchmark prices were higher than 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 $3.96 and $4.68 per mcf for natural gas compared to our reported prices of $4.11 and $5.00 per mcf. Our reported adjusted sales prices for crude oil would have been $92.87 and $95.26 per barrel for the current reporting periods compared to our reported prices of $93.10 and $97.11 per barrel.

Our unrealized gains for the current reporting periods resulted from all outstanding commodity benchmarked indexed derivative contracts on September 30, 2014 relative to the marked-to-market liability values of these same contracts as at June 30, 2014 and December 31, 2013. These unrealized gains primarily resulted from lower notional volumes remaining on the contractual terms.

Net Financing Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2014**	2013	**2014**	2013
Interest on bank debt	**$ 837**	$ 1,148	**$ 2,482**	$ 3,609
Interest earned	**(3)**	(34)	**(173)**	(357)
Finance charges and fees	**78**	75	**194**	202
Amortization of deferred financing costs	**195**	73	**343**	195
Accretion of decommissioning obligation	**681**	647	**2,031**	1,965
Total	**$ 1,788**	$ 1,909	**$ 4,877**	$ 5,614

The decreases 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. In addition, we incurred lower interest on bank debt as a result of our repayment of the outstanding debt balance as financed from the Tunisian Disposition Transaction proceeds (see "Credit Facility" section of this MD&A).

Our average effective interest rates during the current reporting periods of 4.6% and 4.2% decreased from 5.4% and 5.3% 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 EBITDA. 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 revolving credit facility. The amortization of deferred financing costs increased during the current reporting periods as we expensed the remaining outstanding balance during the third quarter in conjunction with the repayment of our entire outstanding principal.

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

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2014**	2013	**2014**	2013
Depletion, depreciation and amortization	**$ 11,503**	$ 12,067	**$ 36,136**	$ 39,297
Per sales ($/boe)	**$ 17.04**	$ 15.68	**$ 17.14**	$ 17.26

DD&A expense during the current reporting periods, on an overall dollar basis, decreased compared to the same periods of 2013 as we reported lower overall sales volumes primarily from our 2013 non-core property disposition program. On a boe basis, the increase in DD&A expense during the third quarter resulted from higher amortization associated with the 19 additional sections of 100% working interest land in the Birley/Umbach area that we acquired at the May Crown land sale.

Impairment of Development & Production Assets

At September 30, 2014, we determined that there were no indications of impairment that would warrant conducting an impairment test in respect of any of our CGUs.

Gains on Disposition of Properties

During the year to date, we completed the sale of several petroleum and natural gas properties located throughout Alberta and British Columbia for aggregate proceeds of $5.4 million (2013 – $19.7 million). The carrying amount of these properties, including the disposed decommissioning obligation, was less than the sales proceeds received resulting in a gain of $2.9 million for the year to date compared to $13.0 million for the same period of 2013.

Foreign Exchange & Other (Gains) Losses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2014**	2013	**2014**	2013
Foreign exchange and other (gains) losses	**$ (2,079)**	$ (165)	**$ (2,380)**	$ 82

During the current reporting periods we recognized foreign exchange gains. These gains resulted from holding US dollar denominated Tunisian Disposition Transaction proceeds prior to conversion to Canadian dollars.

Income Tax Expense

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.

Discontinued Tunisian Operations

The operating results for the Discontinued Tunisian Operations are shown in the following table for the noted periods:

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2014**[(1)]	2013	**2014**[(1)]	2013
Discontinued Operations				
Crude oil & natural gas revenues	**$ 1,367**	$ 19,340	**$ 36,911**	$ 52,815
Royalties & expenses	**(3,066)**	(15,165)	**(29,398)**	(38,495)
(Loss) income from discontinued operations	**(1,699)**	4,175	**7,513**	14,320
Gain on sale of discontinued operations	**1,037**	-	**1,037**	-
Realized accumulated other comprehensive income on the disposition of foreign operations	**9,546**	-	**9,546**	-
Income tax expense	**(1,108)**	(47)	**(3,787)**	(2,716)
Net income from discontinued operations	**$ 7,776**	$ 4,128	**$ 14,309**	$ 11,604

(1) During the current reporting periods, the Discontinued Tunisian Operations periods ended on August 19, 2014, the date that the Tunisian Disposition Transaction closed.

Relative to the three and nine months ended September 30, 2013, income before income taxes decreased for the current reporting periods. These decreases resulted from lower sales volumes during the current reporting periods which in turn led to lower crude oil and natural gas revenues. The lower sales volumes were partially due to the shorter current reporting periods. During the third quarter, the shorter reporting period did not allow us to accumulate sufficient crude oil production volumes to make a delivery to a tanker. This resulted in us storing the crude oil production and reporting the associated costs (royalties, operating and DD&A), as part of this inventory's carrying value. This resulted in decreases to these expenses during the current reporting periods as compared to the three and nine months ended September 30, 2013. On August 19, 2014, the inventory carrying value, along with the other net assets of this discontinued operation, were less than the disposition proceeds, net of transaction costs. This resulted in a gain on the sale of discounted operations of $1.0 million.

Upon the completion of the Tunisian Disposition Transaction, we recognized $9.5 million as realized foreign exchange as included in net income from discontinued operations. This amount had previously been accumulated from foreign currency translations of the discontinued operations' net assets as reported as other comprehensive income.

Net Income and Comprehensive Income

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	2014	2013	2014	2013
Weighted average shares outstanding – basic (thousands)	**214,895**	214,188	**214,439**	214,188
Dilutive impact of share options, restricted awards and performance awards (thousands)	**1,878**	-	**1,151**	-
Weighted average shares outstanding – diluted (thousands)	**216,773**	214,188	**215,590**	214,188
Net income (loss) from continuing operations	**$ 3,696**	$ (316)	**$ 7,639**	$ 698
Per share – basic & diluted ($/share)	**$ 0.02**	$ -	**$ 0.04**	$ 0.01
Net income	**$ 11,472**	$ 3,812	**$ 21,948**	$ 12,302
Per share – basic & diluted ($/share)	**$ 0.05**	$ 0.02	**$ 0.10**	$ 0.06
Comprehensive income	**$ 5,049**	$ 765	**$ 15,707**	$ 15,998
Per share – basic and diluted ($/share)	**$ 0.02**	$ -	**$ 0.07**	$ 0.07

Our net income from continuing operations of $3.7 million and $7.6 million in the current reporting periods increased relative to the same periods of 2013. These increases resulted from both higher realized commodity pricing and foreign exchange gains in addition to both lower net financing and DD&A expenses. Also affecting the third quarter increase was higher gains from both property dispositions and derivative contracts. The year to date increase also benefited from lower exploration & evaluation expenses, despite a decrease in gains from property dispositions which was $13.0 million as reported in the same period of 2013.

Net income includes that from both our continuing and discontinued operations (see “Discontinued Tunisian Operations”). The net income from discontinued operations for the current reporting periods of $7.8 million and $14.3 million includes the financial results of the Discontinued Tunisian Operations for 50 and 231 days ended August 19, 2014, the date control ceased. Despite a smaller time frame, the net income from discontinued operations increased in comparison to the three and nine months ended September 30, 2013. These increases resulted from two measures from the sale of the Discontinued Tunisian Operations: a $1.0 million gain on sale and the realization of $9.5 million of foreign exchange gains as accumulated from the net assets of these operations but as offset in other comprehensive income.

Comprehensive income includes our net income and foreign currency translation losses and gains of the US dollar denominated Discontinued Tunisian Operations. Given our sale of the Discontinued Tunisian Operations, in future reporting periods we will no longer be reporting foreign exchange gains/losses on foreign operations. For the current reporting periods ended August 19, 2014, we recognized foreign exchange gains as the carrying value of the Discontinued Tunisian Operations on translation from its functional US dollar increased as reported in Canadian dollars. On disposition of these operations, and as mentioned, we moved the $9.5 million of accumulated other comprehensive income to net income from discontinued operations. This move had a nil effect on comprehensive income.

Capital Resources, Capital Expenditures and Liquidity

On October 29, 2014, we announced that our Board of Directors had approved a $135.0 million 2015 capital program focusing on the development of our liquid rich natural gas at Birley/Umbach, British Columbia and light crude oil at Grande Prairie, Alberta. As at September 30, 2014, with no outstanding debt balance and $35.3 million of working capital, which includes $47.5 million of cash on hand, we intend to finance this capital program from our existing working capital, cash flows and draws against our credit facility in respect of which we have $125.0 million of available credit. Cash flows are anticipated to be sufficient to repay any drawn debt used to finance the 2015 capital program prior to the end of 2016. If required for an expanded capital program or acquisition, we could also consider an equity offering if the market conditions improve.

For the year to date, we financed the repayment of all outstanding debt and our investment in capital, decommissioning, exploration and evaluation expenditures (including our sizeable land acquisition) from cash on deposit, cash flows, non-cash working capital and proceeds from the sale of both our Discontinued Tunisian Operations and property dispositions.

Net Consideration from Sale of Discontinued Tunisian Operations and Other Associated Expenditures, Commitments and Guarantees

Net Consideration

Chinook’s wholly-owned subsidiary, SVI (BVI), received the following consideration from the sale of the Discontinued Tunisian Operations:

	August 19
($ thousands)	2014
Consideration on sale of discontinued operations	**$ 140,480**
Cash transaction costs	**(7,645)**
Net consideration	**$ 132,835**

As of the date of this MD&A, all consideration from the sale of the Discontinued Tunisian Operations has been received from the purchaser except for the settlement of a post-closing working capital adjustment. Our investment in SVI (BVI) had sufficient surplus tax pools which allowed us to repatriate $132.8 million of cash proceeds from the British Virgin Islands to Canada without incurring any adverse Canadian tax effects. The remainder of the cash proceeds were left in the British Virgin Islands to finance cash transaction costs.

Transaction Costs

Transaction costs, as included against the net income of discontinued operations, include both cash and non-cash expenses. Cash transaction costs of $7.6 million include a success fee to our advisor and expenses for legal fees and severance of our Canadian-based staff dedicated to the Discontinued Tunisian Operations. Included in this severance expense is $1.6 million for our international officers.

Transaction costs also include another $2.3 million of non-cash costs which included the following:

- As a condition precedent to the closing of the Tunisian Disposition Transaction, we cancelled our US$75.0 million international amortizing reserve-based credit facility. On cancellation of this facility, we accelerated the amortization of the associated deferred financing costs. As the cancellation of this facility was a condition precedent of the Tunisian Disposition Transaction, we expensed $2.1 million of deferred financing costs as non-cash transaction costs. We had not drawn on this facility at the time it was cancelled.
- As a result of the surrendering and acceleration of vesting dates of certain options held by optionees dedicated to the Discontinued Tunisian Operations (see below for "Other Expenditures" and "Other Commitments"), the associated unamortized fair value of these options was reported as a non-cash transaction cost of $0.2 million.

Other Expenditures

During the current reporting periods, and as a result of the sale of the Discontinued Tunisian Operations, we paid $0.9 million to certain Tunisian-based optionees in consideration for them voluntarily surrendering 1,383,750 of "in-the-money" options. This cash payment represented the fair value of "in-the-money" options at the time of their surrender. It was reported as an increase in the line item of contributed surplus as included on the statements of financial position. We also accelerated the vesting date of 311,668 options to August 19, 2014, the date the PSA closed. These options were then exercised by the remaining Tunisian-based optionees at a weighted average exercise price of $1.14 per option. None of these Tunisian-based optionees were officers.

Other Commitments and Guarantees

Included in the terms of the PSA, SVI (BVI) has made normal course indemnifications to the purchaser, as specifically guaranteed by Chinook Energy Inc.

We also committed to certain Canadian-based optionees who were previously dedicated to the Discontinued Tunisian Operations, including our international officers, that their unvested options will vest on December 1, 2014. At that time, and consistent with our option plan, these Canadian-based optionees will then have 60 days to exercise any of their "in-the-money" options. At September 30, 2014, we anticipate that 325,837 options held by these Canadian-based optionees with a weighted average exercise price of $1.32 per option will have their vesting dates accelerated, of which 193,335 options are held by our international officers with a weighted average exercise price of $1.34 per option.

Cash Flow from Continuing Operations

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per share amounts)	**2014**	2013	**2014**	2013
Cash flow from continuing operations	**$ 16,597**	$ 14,214	**$ 38,055**	$ 15,198
Add back (deduct):				
Change in operating non-cash working capital	**(7,503)**	(3,036)	**2,274**	15,030
Decommissioning obligation expenditures	**599**	1,035	**1,760**	2,100
Cash flow from continuing operations[(1)]	**$ 9,693**	$ 12,213	**$ 42,089**	$ 32,328
Per share – basic and diluted [(1)]	**$ 0.05**	$ 0.06	**$ 0.20**	$ 0.15
Per sales ($/boe)[(1)]	**$ 14.36**	$ 15.90	**$ 19.96**	$ 14.21

(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 from continuing operations increased by 30% to $42.1 million compared to the same period of 2013. This increase is due to higher crude oil sales volumes and its higher associated netback, compared to the netback of an equivalent boe of natural gas. Stronger realized 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 third quarter decreased from the same quarter of 2013 despite an increase in the netback. This decrease was due to lower commodity sales volumes and realized derivative contract losses. The increased netback was due to the effect of a higher ratio of crude oil sales volumes in relation to total sales volumes, in combination with oil's higher associated netback and higher realized commodity pricing.

Credit Facility

($ thousands)	September 30 2014	December 31 2013[2]
Long-term debt	**$ -**	$ 75,897
Less:		
Working capital excluding mark-to-market derivative contracts[1]	**(35,870)**	(14,048)
Net debt (surplus)[1]	**$ (35,870)**	$ 61,849

(1) Net debt (surplus) and working capital excluding mark-to-market derivate contracts are non-IFRS measures. Net debt (surplus) 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 (surplus) 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 (surplus), 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.

(2) Includes balances related to the Discontinued Tunisian Operations which was sold during the third quarter.

We had a surplus of $35.9 million at September 30, 2014, as compared to net debt of $61.8 million at December 31, 2013. This change of $97.7 million from net debt to surplus is primarily due to the proceeds of $140.5 million received from the sale of the Discontinued Tunisian Operations, proceeds of $5.4 million from Canadian non-core property dispositions, cash flow from continuing operations of $42.1 million and $1.9 million of foreign exchange gains on cash, less capital, decommissioning, exploration and evaluation expenditures of $54.4 million and the effect of the Discontinued Tunisian Operations. This effect includes relinquished working capital, cash-based transaction costs and the amortization of deferred financing costs for a total of $32.6 million.

During the third quarter we repaid our Canadian credit facility and amortized $0.2 million of deferred financing costs related to this facility. As at September 30, 2014, we had no outstanding borrowings compared to the $78.5 million in borrowings as 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 September 30, 2014, we had no drawings under this facility but had outstanding letters of credit of $0.3 million. This resulted in available credit on this facility of $124.7 million (December 31, 2013 – drawings of $78.5 million, outstanding letters of credit of $0.4 million and $36.1 million in available credit).

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 included 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 September 30, 2014, since we have no outstanding bank debt, we were in compliance with this covenant and anticipate being in compliance through the existing term of this facility.

During the third quarter, and pursuant to the repayment of debt, the remaining unamortized deferred financing costs of $0.2 million related to the Canadian Revolving Term Credit Facility were amortized to net financing expense.

Capital Expenditures

Capital expenditures were as follows:

	Three months ended September 30		Nine months ended September 30	
($ thousands)	2014	2013	2014	2013
Land and lease	**$ 132**	$ 493	**$ 14,334**	$ 3,255
Drilling and completions	**10,559**	6,655	**30,282**	21,454
Facilities and equipment	**3,206**	2,602	**11,072**	7,160
Field expenditures	**13,897**	9,750	**55,688**	31,869
Capitalized G&A	**309**	262	**851**	829
Furniture and equipment	**95**	2	**374**	34
Total	**$ 14,301**	$ 10,014	**$ 56,913**	$ 32,732
Proceeds from dispositions	**$ 5,414**	$ 3,283	**$ 5,446**	$ 19,703

During the third quarter we drilled four (2.38 net) wells, including one (0.75 net) horizontal Montney gas well on our Birley/Umbach property in northeastern British Columbia along with two (1.26 net) horizontal Dunvegan oil wells and one (0.37 net) vertical Cardium water disposal well in the Grande Prairie area of Alberta. In addition, we drilled a side track on one of the Dunvegan crude oil wells (1.0 net) that we drilled during the first quarter of 2014. A summary of our drilling activities for the current reporting periods is as follows:

	Three months ended September 30, 2014		Nine months ended September 30, 2014	
	Gross	Net	Gross	Net
Development wells				
Oil	2.00	**1.26**	6.00	**4.52**
Gas	-	**-**	1.00	**0.37**
Development wells	2.00	**1.26**	7.00	**4.89**
Exploration gas well	1.00	**0.75**	2.00	**1.50**
Disposal/injection	1.00	**0.37**	1.00	**0.37**
Total	4.00	**2.38**	10.00	**6.76**

The Birley/Umbach well, the second horizontal Montney well we have drilled in this area this year, was successfully completed during third quarter. The well is currently shut-in to acquire pressure build-up data, with first production anticipated prior to year-end. Continuous production from our first well at Birley/Umbach (0.75 net) (which was drilled, completed and tested in early 2014) resumed in August 2014 following some modifications to compression facilities. Restricted production rates have averaged four mmcfpd and 100 barrels of condensate per day (780 boepd, not including NGLs) over the first 90 operating days. Work is underway to increase throughput capacity to 10 mmcfpd at the current compression facility during the fourth quarter of 2014. We intend to drill six (5.6 net) more horizontal wells at Birley/Umbach in the upcoming winter drilling season, build a new pipeline, and construct a new compression facility which will increase gas takeaway capacity to 35 mmcfpd by the end of the second quarter of 2015. A further six (5.5 net) horizontal wells are planned for the second half of 2015.

At our Albright field, we drilled one (1.0 net) operated horizontal Dunvegan oil well and re-drilled the horizontal section of a first quarter 2014 well (1.0 net) during the third quarter, both of which were brought on production in the fourth quarter. We have eleven (9.0 net) horizontal wells that were drilled and brought on production in this field since January 2013 and have one (0.5 net) additional well planned for the fourth quarter of 2014. The other third quarter horizontal Dunvegan oil well (non-operated, 0.26 net) drilled in the Karr field, will be completed and brought on production later during the fourth quarter. We have eleven (3.43 net) horizontal oil wells drilled at Karr, with four (1.37 net) more wells planned for the fourth quarter of 2014 and the first quarter of 2015.

The Cardium water disposal well (0.37 net) was drilled at Gold Creek to handle produced water from our first horizontal Montney oil well (0.37 net, final test rates of 500 bopd and 6 mmcfpd), which was drilled in the first quarter of 2014 and is anticipated to begin producing during the fourth quarter of 2014. The water disposal well is expected to be in use during the first quarter of 2015. We spud one (0.75 net) additional horizontal Montney well in the Gold Creek area during October of 2014.

Decommissioning Obligation

At September 30, 2014, we had decommissioning obligations of $84.5 million (December 31, 2013 – $85.4 million, related to continuing operations) for the future abandonment and reclamation of our properties. During the year to date, we incurred Canadian abandonment and reclamation expenditures of $1.8 million and disposed of properties with associated decommissioning obligations of $1.5 million (same period of 2013 – $2.1 million and $9.8 million, respectively) which decreased our obligation. Offsetting these decreases were additions related to our year to date Canadian drilling program estimated at $0.4 million (same period of 2013 – $0.6 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 $2.0 million, respectively, were comparable to the charges reported during the same periods of 2013.

As at September 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 September 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:

	September 30 2014	December 31 2013
Common shares outstanding	**215,078,677**	214,187,681
Share options	**9,646,674**	14,319,699
Restricted awards	**192,310**	-
Performance awards	**225,325**	-
Weighted average common shares		
- basic	**214,439,125**	214,187,681
- diluted	**215,589,826**	214,187,681

As at November 12, 2014, we had 215,081,438 common shares, 9,541,842 share options, 192,310 restricted awards and 225,325 performance awards outstanding.

Share Award Incentive Plan

Beginning on June 26, 2014, we began granting restricted awards and 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 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.

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 September 30, 2014, we had the following commodity price contracts with an estimated fair value current liability of $0.6 million:

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

Based on guidance, these price risk contracts are expected to secure our received commodity prices on approximately 22% and 34% of sales volumes from crude oil and natural gas, respectively.

Outlook

As announced in our news release dated October 29, 2014, our Board of Directors has approved a $135 million capital program for 2015 focusing on the development of liquids rich natural gas at Birley/Umbach, British Columbia and light oil at Grande Prairie, Alberta.

2015 Capital Program

In 2015, we intend to move towards full scale development and facility expansion at Birley/Umbach, further delineation at Gold Creek and continue with our Dunvegan oil development program. The breakdown of our 2015 capital program by category and area is as follows:

2015 Capital Program by Category

Expenditure Type	$ Millions	%
Drilling, completion, equip and tie-in	**$ 93**	**69**
Facilities and infrastructure	**23**	**17**
Land and seismic	**11**	**8**
Optimizations, turnarounds and abandonments	**8**	**6**
	$ 135	**100**

2015 Capital Program by Area

Area – Zone	$ Millions
Birley/Umbach (Montney)	$ 97
Grande Prairie (Montney)[(1)]	10
Grande Prairie (Dunvegan)	21
Other	7
	$ 135

(1) Additional well(s) may be included in 2015 and are contingent on results of current drilling operations at 14-12-69-6 W6 (Chinook 75%).

Birley/Umbach, British Columbia

We plan to drill six (5.6 net) wells in the first quarter of 2015 and expand our existing facility, which will increase current throughput capacity from four mmcf/d to approximately 35 mmcf/d, upon completion in the second quarter of 2015. Following spring break-up, we expect to drill up to six (5.5 net) additional wells in the third quarter of 2015.

Grande Prairie, Alberta – Montney

At Gold Creek, we have budgeted a follow up development well (0.375 net) expected to be drilled in the third quarter of 2015. Facility construction and pipeline tie-in of our first well are complete and we anticipate bringing the well on production by mid-November 2014. In addition, we are currently drilling a second Montney well (75% working interest) at Gold Creek which, if successful, may justify an expansion of our budgeted 2015 capital program along with pending results from several recent wells drilled by other operators immediately offsetting our 50 (35 net) sections of Montney lands at Gold Creek.

Grande Prairie Area, Alberta – Dunvegan

We plan to drill four (4 net) wells at Albright and six (2 net) wells at Karr in the second half of 2015.

Updated 2014 Guidance and Guidance for 2015

Further to our news release dated October 29, 2014, we have acquired, effective September 1, 2014, approximately 1,200 boe/d (86% natural gas) of production near our Birley/Umbach operations along with operatorship of strategic infrastructure that will provide us flexibility with respect to our gas processing and transportation options as we continue to develop this area. The purchase price of the acquisition was $17 million in cash plus 3.5 net sections of non-core lands in the Wapiti area of Alberta.

In our October 29, 2014 news release, we updated our 2014 guidance in light of the foregoing acquisition, lower forecasted fourth quarter commodity prices, timing delays in the on stream date of our first Gold Creek Montney well and the closing of the Tunisia Disposition Transaction. We also provided guidance for 2015. Both are set forth below:

($ millions, except boe/d)	Previous 2014 Guidance	Updated 2014 Guidance	2015 Guidance
Production (boe/d)	7,750 – 8,250	**7,900 – 8,000**	**10,500 – 11,500**
Exit production (boe/d)	N/A	**9,100 – 9,400**	**13,250 – 13,750**
Cash flow (1)(2)	$58 – $60	**$54 – $56**	**$62 – $66**
Capital expenditures (3)	$81	**$93**	**$135**
Net debt (surplus) (1)(2)(4)	N/A	**($8)**	**$60 – $65**

(1) 2014 pricing assumptions: Canadian crude oil of $92.95/bbl; Canadian natural gas of $4.79/mcf.

(2) 2015 pricing assumptions: Canadian crude oil of $84.49/bbl; Canadian natural gas of $4.08/mcf.

(3) Updated 2014 capital expenditures guidance includes net acquisitions/dispositions anticipated for the year.

(4) We are forecasting positive working capital and no drawn bank debt as at December 31, 2014.

Quarterly Information from Continuing Operations

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

	Sep. 30 2014	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013	Sept. 30 2013	Jun. 30 2013	Mar. 31 2013	Dec. 31 2012
CONTINUING OPERATIONS								
Sales Volumes								
Oil (bbl/d)	**1,823**	2,267	2,084	1,840	1,853	1,606	1,549	1,514
Natural gas liquids (bbl/d)	**678**	715	950	722	753	874	1,005	1,003
Natural gas (mcf/d)	**29,028**	29,570	29,364	32,287	34,563	33,226	36,468	38,529
Average daily sales (boe/d)	**7,339**	7,911	7,928	7,943	8,367	8,018	8,633	8,939
Sales Prices								
Average oil price ($/bbl)	**$ 93.10**	$ 101.01	$ 96.41	$ 81.18	$ 97.53	$ 92.43	$ 82.65	$ 78.43
Average natural gas liquids price ($/bbl)	**$ 64.71**	$ 72.06	$ 74.10	$ 63.74	$ 62.36	$ 55.06	$ 58.85	$ 57.71
Average natural gas price ($/mcf)	**$ 4.11**	$ 4.89	$ 6.01	$ 3.57	$ 2.55	$ 3.74	$ 3.34	$ 3.09
Netback(1)								
Average commodity pricing ($/boe)	**$ 45.37**	$ 53.75	$ 56.50	$ 39.09	$ 37.76	$ 40.02	$ 35.80	$ 33.07
Royalties ($/boe)	**$ (6.90)**	$ (8.47)	$ (6.01)	$ (4.80)	$ (3.53)	$ (5.23)	$ (4.08)	$ (0.15)
Net production expenses ($/boe)(1)	**$ (17.44)**	$ (17.06)	$ (16.91)	$ (15.83)	$ (16.42)	$ (15.55)	$ (14.96)	$ (17.04)
Cash G&A ($/boe)(1)	**$ (4.32)**	$ (4.30)	$ (6.46)	$ (3.47)	$ (1.71)	$ (2.76)	$ (3.07)	$ (4.72)
Netback ($/boe)(1)	**$ 16.71**	$ 23.92	$ 27.12	$ 14.99	$ 16.10	$ 16.48	$ 13.69	$ 11.16
Wells Drilled (net)								
Oil	**1.26**	-	3.26	1.65	3.00	-	3.61	1.24
Gas	**0.75**	-	1.12	-	-	-	-	-
Disposal/injection	**0.37**	-	-	-	-	-	-	-
Total wells drilled (net)	**2.38**	-	4.38	1.65	3.00	-	3.61	1.24
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties	**$ 25,972**	$ 32,596	$ 36,029	$ 25,056	$ 26,347	$ 25,385	$ 24,646	$ 27,073
Cash flow(1)	**$ 9,693**	$ 14,801	$ 17,594	$ 8,786	$ 12,213	$ 10,662	$ 9,453	$ 9,490
Per share – basic and diluted ($/share)	**$ 0.05**	$ 0.07	$ 0.08	$ 0.04	$ 0.06	$ 0.05	$ 0.04	$ 0.04
Net income (loss) from continuing operations (2)	**$ 3,696**	$ 3,533	$ 410	$ (10,151)	$ (316)	$ 3,682	$ (2,668)	$ (45,326)
Per share – basic and diluted ($/share)	**$ 0.02**	$ 0.02	$ 0.00	$ (0.05)	$ (0.00)	$ 0.02	$ (0.01)	$ (0.21)
Net income (loss) (2)(3)(4)	**$ 11,472**	$ 4,391	$ 6,085	$ (39,002)	$ 3,812	$ 3,989	$ 4,500	$ (36,708)
Per share – basic and diluted ($/share)	**$ 0.05**	$ 0.02	$ 0.03	$ (0.18)	$ 0.02	$ 0.02	$ 0.02	$ (0.17)
Capital expenditures	**$ 14,301**	$ 18,998	$ 23,614	$ 9,853	$ 10,014	$ 5,506	$ 17,212	$ 36,148
Net debt (surplus)(1)(5)	**$ (35,870)**	$ 80,536	$ 74,390	$ 61,849	$ 65,105	$ 66,340	$ 64,440	$ 72,383
Total assets(5)	**$ 472,241**	$ 589,515	$ 604,419	$ 555,341	$ 593,192	$ 621,143	$ 617,459	$ 622,476
Common Shares *(thousands)*								
Weighted average during period – basic	**214,895**	214,226	214,188	214,188	214,188	214,188	214,188	214,188
Weighted average during period – diluted	**216,773**	215,814	214,245	214,188	214,188	214,188	214,188	214,188
Outstanding at period end	**215,079**	214,674	214,188	214,188	214,188	214,188	214,188	214,188

(1) Cash flow, cash flow per share, net debt (surplus), 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) Includes $55.5 million and $3.5 million in impairment charges against properties for the three months ended December 31, 2012 and 2013, respectively.

(3) Includes net income from discontinued operations where we also reported $32.0 million in impairment charges against Discontinued Tunisian Operations for the three months ended December 31, 2013.

(4) Significant crude oil production from the Discontinued Tunisian Operations of 88,000 barrels and 36,000 barrels was not sold at March 31, 2013 and June 30, 2014, respectively.

(5) Quarters prior to the third quarter of 2014 includes the Discontinued Tunisian Operations and their assets or working capital excluding marked-to-market derivative contracts.

Factors That Have Caused Variations over the Quarters

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

Generally, our non-core property disposition program, which continued through 2013, resulted in a lower trend of natural gas and natural gas liquids production volumes. This effect was partially offset by increased crude oil production resulting from the partial reinvestment of our disposition proceeds into core area crude oil properties. When combined with the effects of the Edmonton par and AECO benchmarks which have generally trended up since the fourth quarter of 2012, petroleum and natural gas revenues, net of royalties, have recovered from 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 2013. An increase in capital expenditures, including sizeable Montney land acquisitions, started to increase net debt in 2014 until the third quarter where a portion of the proceeds from the Tunisian Disposition Transaction financed the repayment of our entire outstanding debt balance. Our disposition of non-core assets and our management of organic growth relative to our existing cash flows have allowed us to avoid having to raise proceeds through the issuance of our common shares.

Please refer to "Continuing Canadian 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 Standards Not Yet Adopted

In July 2014, the International Accounting Standards Board issued a new accounting standard related to the classification, measurement, impairment and the impact of credit on financial instruments, which forms part of IFRS 9, *Financial Instruments*. As part of the new standard the classifications of financial assets will be based on their cash flow characteristics and the business model in which the assets are held. When assessing impairment on financial instruments, the new standard requires more timely recognition of expected credit losses. IFRS 9 also eliminates the recognition in profit or loss of changes in the fair value of liabilities related to a change in a company's own credit risk. This new standard along with the new general hedge accounting standard issued in November 2013 as part of IFRS 9, come into effect for periods beginning on or after January 1, 2018, with early adoption permitted. We have not completed our assessment of the impact of the above standards.

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 September 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 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 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 July 1, 2014 and ended on September 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 regarding our company, including management's assessment of our future plans and operations, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: budgeted amounts in fiscal 2015, expectations that such amounts will be spent in the manner, location and timeframes set forth herein, expectations as to how we will fund the 2015 capital program, expectations of our 2015 capital program by category and geographic area, the number of wells budgeted for drilling and the timing thereof at certain of our core areas, future exploration and development activities and the timing thereof, various matters related to the recently completed Birley/Umbach acquisition, including the effect of the acquisition on our continuing operations and on our production volumes and the benefits anticipated to be derived therefrom, as well as our expectations regarding production, cash flow, capital expenditures and net debt (surplus) set out in the table under the heading "Outlook – Updated 2014 Guidance and Guidance for 2015".

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, future capital expenditure levels, future oil and natural gas prices, future oil and natural gas production levels, future currency, exchange and interest rates, our ability to obtain equipment in a timely manner to carry out exploration and development activities, the ability of the operator of the projects of which we have an interest in to operate in the field in a safe, efficient and effective manner, the impact of increasing competition, field production rates and decline rates, anticipated production volumes, our ability to replace and expand production and reserves through exploration and development activities, certain commodity price and cost assumptions, the results of negotiations and the plans of our partners in certain of our areas; that the budgeted amounts and expenditures set forth herein, which are subject to the discretion of our Board of Directors, will not be amended in the future, and the continued availability of adequate debt 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, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, our Board of Directors may amend the 2015 capital program based on its discretion; environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increased or unforeseen 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 inability 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 reports on file with Canadian securities regulatory authorities and 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. Boes 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.

Initial Production Levels

Any references in this MD&A to initial, early and/or test production/performance rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating our aggregate production. The initial production rate may be estimated based on other third party estimates or limited data available at this time. The initial production is generally estimated using boes. In all cases in this MD&A initial production or test rates are not necessarily indicative of long-term performance of the relevant well or fields or of ultimate recovery of hydrocarbons.

Future Oriented Financial Information

This MD&A, in particular the information in respect of anticipated cash flows, may contain Future Oriented Financial Information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by our management to provide an outlook of our activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed under the heading "Forward-Looking Statements" and assumptions with respect to production rates and commodity prices. The actual results of our operations and the resulting financial results may vary from the amounts set forth herein, and such variation may be material. Our management believes that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments.