MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis as provided by the management of Raging River Exploration Inc. ("Raging River" or the "Company") is dated November 6, 2014 and should be read in conjunction with the unaudited interim financial statements for the three and nine months ended September 30, 2014 and the audited financial statements for the year ended December 31, 2013 and the notes thereto. The interim financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 – "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are referenced in Canadian dollars.

Forward Looking Statements

This Management Discussion and Analysis ("MD&A") may include forward-looking statements including opinions, assumptions, estimates and management's assessment of future plans and operations, expected royalty rates, expected transportation costs, expected capital expenditures, expectations that the company will have adequate liquidity to fund operations and capital expenditures and the timing and funding thereof. When used in this document, the words "anticipate", "believe", "estimate", "expect", "intent", "may", "project", "plan", "should" and similar expressions are intended to be among the statements that identify forward-looking statements. Forward-looking statements are subject to a wide range of risks and uncertainties, and although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will be realized. Any number of important factors could cause actual results to differ materially from those in the forward-looking statements, including, but not limited to, risks associated with petroleum and natural gas, exploration, development, exploitation, production, marketing and transportation, the volatility of petroleum and natural gas prices, currency fluctuations, the ability to implement corporate strategies, the state of domestic capital markets, the ability to obtain financing, incorrect assessments of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in petroleum and natural gas acquisition and drilling programs, delays resulting from inability to obtain required regulatory approvals, delays resulting from other producers, imprecision or reserve estimates, labour supply risks, environmental risks, competition from other producers, imprecision of reserve estimates, changes in general economic conditions, whether farm-in and farm-out opportunities result in agreements and other factions more fully described from time to time in the reports and filings made by the Company with securities regulatory authorities including the Company's most recent annual information form. Statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. The forward looking statements contained in this MD&A are expressly qualified by this cautionary statement. Readers are cautioned not to place undue reliance on forward-looking statements, as no assurances can be given as to future results, levels of activity or achievements. Except as required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements.

Non-GAAP Measures

The MD&A contains the term funds flow from operations which should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. The reconciliation between cash flow from operating activities and funds flow from operations can be found in the statement of cash flows in the unaudited interim financial statements and is presented before the change in non-cash operating working capital. The Company reconciles funds flow from operations to cash flow from operating activities, which is the most directly comparable measure calculated in accordance with IFRS, as follows:

	Three months ended September 30,		Nine months ended, September 30,	
	2014	2013	2014	2013
	(thousands of dollars)			
Cash flow from operating activities	63,013	28,444	158,200	66,858
Changes in non – cash working capital	(5,163)	3,730	5,746	14,226
Funds flow from operations	57,850	32,174	163,946	81,084

The Company presents funds from operations per share whereby per share amounts are calculated consistent with the calculation of earnings per share.

The MD&A contains other terms such as net debt and operating netbacks, which are not recognized measures under IFRS. Management believes these measures are useful supplemental measures of firstly, the total amount of current and long-term debt the Company has, and secondly, the amount of revenues received after the royalties, operating and transportation costs. Net debt represents current assets less current liabilities and bank debt is used to assess efficiency, liquidity and the general financial strength of the Company. Mark-to-market risk management contracts are excluded from the net debt calculation. Readers are cautioned however, that these measures should not be construed as an alternative to other terms such as current and long-term debt or net earnings in accordance with IFRS as measures of performance. The Company's method of calculating these measures may differ from other companies, and accordingly, may not be comparable to measures used by other companies.

The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Per boe amounts have been calculated using a conversion rate of nine thousand cubic feet of natural gas to one barrel of oil. This equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Description of the Company

Raging River was incorporated as 1646988 Alberta Ltd. pursuant to the *Business Corporations Act* (Alberta) on December 15, 2011 and subsequently changed its name to Raging River Exploration Inc. Raging River is a crude oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in the Dodsland area of southwest Saskatchewan.

Unless otherwise indicated herein, all production information presented herein has presented on a gross basis, which is the Company's working interest prior to deduction of royalties and without including any royalty interests.

Corporate Highlights

Third quarter ended September 30, 2014

- Achieved record average production of 10,679 boe/d (95% oil), an increase of 7% from the second quarter of 2014 and an increase of 88% over the comparable period in 2013.

- Attained record corporate funds flow from operations of $57.9 million ($0.32/share basic), an increase of 3% from the second quarter 2014 funds flow from operations of $56.3 million.

- Achieved industry leading operating netbacks of $67.68/boe and funds flow netbacks of $58.87/boe.

- Achieved record net earnings of $31.5 million ($0.17/share basic) or $32.07/boe.

- Achieved a 6% reduction in operating costs to $11.75/boe from the comparable period in 2013.

- Attained top decile general and administrative costs of $1.39/boe, a 25% decrease from the comparable period in 2013.

- The Company invested a total of $81.7 million on capital expenditures including $76.5 million on drilling, completion and production facilities, and $5.1 million on land and property acquisitions. The Company drilled a total of 87 (69.7 net) wells including 86 horizontal Viking oil wells at a 99% success rate and one vertical stratigraphic test well.

- Maintained balance sheet strength with third quarter exit net debt of $113 million representing 0.5 times debt to the third quarter annualized cash flow.

Petroleum and Natural Gas Revenue

	Three months ended September 30, 2014	2013	Percent Change	Nine months ended September 30, 2014	2013	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Liquids revenue	87,604	50,033	75	254,667	118,819	114
Natural gas revenue	828	246	237	3,099	865	258
Royalty revenue	134	8	1,575	438	18	2,333
	88,566	50,287	76	258,204	119,702	116
Operating: (6:1 boe conversion)						
Average daily production						
Liquids (bbls/d)	10,278	5,495	87	9,738	4,782	104
Natural gas (mcf/d)	2,406	1,104	118	2,480	1,030	141
Barrels of oil equivalent (boe/d)	10,679	5,679	88	10,152	4,954	105
Average Raging River sales price						
Liquids ($/bbl)	92.79	98.98	(6)	95.96	91.03	5
Natural gas ($/mcf)	3.74	2.43	54	4.58	3.08	49
Barrel of oil equivalent ($/boe)	90.14	96.25	(6)	93.17	88.51	5
Average Benchmark Prices						
Crude Oil - WTI (US$/bbl)	97.17	105.82	(8)	99.61	98.15	1
Crude Oil – Canadian Light	97.71	105.17	(7)	100.53	95.57	5
Natural gas - AECO	4.03	2.43	66	4.78	3.00	59
Exchange rate (US$/Cdn$)	0.92	0.96	(4)	0.91	0.98	(7)

The Company takes almost all of its working interest production "in kind" and it is marketed and sold through various credit-worthy commodity purchasers. Raging River's crude oil is marketed under a short-term (30 day) contract with a crude oil marketer and through major North American crude oil purchasers. All of the Company's natural gas is currently sold as spot gas through significant North American natural gas marketers.

Commodity prices are affected by both domestic and international factors that are beyond the control of the Company. Prices received for crude oil are determined by the quality of the crude compared to the benchmark price for Canadian light, sweet oil. The decline in the WTI price was only slightly offset by the weak Canadian dollar in the third quarter of 2014 which resulted in a lower realized price for the Company. The Company's liquids price averaged $92.79/bbl for the third quarter of 2014, down 6 percent from $98.98/bbl in the third quarter of 2013. Raging River's average quality adjustment to Canadian Light pricing during the third quarter of 2014 was $4.92/bbl compared to $6.19/bbl in the third quarter of 2013.

A weakened Canadian dollar resulted in the higher realized price for the Company in the nine months period ended September 30, 2014, than in the comparable period of 2013. The Company's liquids price averaged $95.96/bbl in the nine months ended 2014, up 5% from the average price of $91.03/bbl received in 2013. Raging River's average quality adjustment to Canadian Light pricing was consistent at $4.57/bbl relative to $4.54/bbl in the comparable period of 2013.

The increase in the AECO natural gas price due to cold winter weather in the first half of 2014 was followed by a decline due to continued supply increases however, on a year to date basis, this resulted in the increase in the natural gas price realized by the Company. Raging River's realized natural gas price in the three and nine month periods ended September 30, 2014, was $3.74 per mcf and $4.58 per mcf respectively, compared to $2.43 per mcf and $3.08 per mcf for the same periods in 2013.

During the third quarter of 2014, the Company drilled a total of 87 (69.7 net) crude oil wells with a 99% success rate, primarily in the greater Dodsland area of southwest Saskatchewan. In the first nine months of 2014, Raging River drilled a total of 185 (157.9 net) wells resulting in 182 (155.9 net) crude oil wells, 1 (0.5 net) stratigraphic test well and 2 (1.5 net) dry holes for an overall success rate of 99%.

Production	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13	Q4/12	Q3/12
Liquids (bbls/d)	10,278	9,500	9,427	7,458	5,495	4,387	4,454	3,027	2,073
Natural gas (mcf/d)	2,406	2,765	2,269	1,912	1,104	1,401	580	618	319
Total (boe/d)	10,679	9,960	9,805	7,777	5,679	4,620	4,550	3,130	2,127
% increase over prior quarter	7%	2%	26%	37%	23%	2%	45%	47%	24%
Production per 1 million shares	59.5	55.5	55.9	47.4	36.2	29.5	29.0	24.6	17.4
Per share % increase (decrease) over prior quarter	7%	(1%)	18%	31%	23%	2%	18%	41%	-

Quarter over quarter, production in the third quarter of 2014 increased to 10,679 boe/d from 9,960 boe/d, an increase of 7 percent. The Company's production for the third quarter of 2014 increased to 10,679 boe/d from 5,679 boe/d in the third quarter of 2013, an increase of 88 percent. The year over year increase of 105 percent was attributable to a successful drilling program in 2013 and 2014 combined with the property acquisition that closed late in the fourth quarter of 2013.

Petroleum and natural gas revenue in the three month period September 30, 2014 was $88.6 million as compared to $50.3 million in the comparable period of 2013. This increase was primarily attributable to an 88 percent increase in production volumes.

Petroleum and natural gas revenues in the nine month period September 30, 2014 were $258.2 million, as compared to $119.7 million in the comparable period of 2013, representing an increase of 116 percent. This increase in revenue is attributed to a combination of a 105 percent increase in production volumes and a 5 percent increase in commodity prices.

Commodity Price Risk Management

Raging River, as part of our financial management strategy, has adopted a disciplined commodity hedging program. The objective of the hedging program is to reduce volatility in the financial results, protect acquisition economics and stabilize cash flow against the unpredictable commodity price environment. As the Company's production grows, our corporate hedging strategy will be restricted to a maximum hedge of 60% of the trailing month's actual production, allowing the Company to participate in commodity price increases while limiting exposure to declines in commodity prices. As of November 6, 2014 the Company has the following price contracts in place by quarter:

2014

Q4

Crude oil	Fixed	Oct 2014 – Dec 2014	2,250 bbls/d	Cdn $105.15/bbl	WTI
Natural gas	Fixed	Oct 2014 – Dec 2014	500 GJs/d	Cdn $3.82/GJ	AECO

2015

Q1

Crude oil	Fixed	Jan 2015 – Mar 2015	450 bbls/d	Cdn $107.00/bbl	WTI

Q2

Crude oil	Fixed	Apr 2015 – Jun 2015	200 bbls/d	Cdn $105.25/bbl	WTI

Realized & unrealized gain/loss on financial instruments

The realized gain/loss represents the commodity contracts settled during the three and nine months ended September 30, 2014. As the oil commodity contracts are referenced to the WTI and settled in Canadian dollars, the realized gains and losses fluctuate based on changes in the WTI price and US/Cdn exchange rate.

The decrease in the WTI in the third quarter was only partially offset by the weak Canadian dollar which resulted in a realized gain for the three months ended September 30, 2014. For the three months ended September 30, 2014, the Company realized gains of $130 thousand (three months ended September 30, 2013: realized losses of $4.0 million).

On a year to date basis, the increase in the WTI in the first half of 2014 combined with a weak Canadian dollar resulted in a realized loss for the nine months period ended September 30, 2014. For the nine months ended September 30, 2014, the Company recorded a $3.6 million loss (nine months ended September 30, 2013: realized losses of $4.1 million).

As of September 30, 2014, the fair value of Raging River's outstanding commodity contracts is an unrealized asset of $1.2 million as reflected in the interim financial statements. The fair value or mark to market value of these contracts is based upon the estimated amount that would have been received as at September 30, 2014, had the contracts been monetized or terminated. Subsequent changes in the fair value of the commodity contracts are recognized in the interim financial statements and could be materially different than what is recorded at September 30, 2014. The unrealized gain of $2.7 million represents the fair value change of the underlying commodity contracts to be settled in the future which has resulted from the decline in WTI forward pricing. In comparison, an unrealized loss of $4.5 million was recorded for the nine months ended September 30, 2013.

In the third quarter of 2014 due to a decline in the WTI price, the Company had unrealized gains of $3.5 million, compared to unrealized losses of $1.9 million in the third quarter of 2013.

Royalties

	Three months ended September 30,		Percent	Nine months ended September 30,		Percent
	2014	2013	Change	2014	2013	Change
	(thousands of dollars)			*(thousands of dollars)*		
Crown	3,049	1,580	93	7,347	3,570	106
Saskatchewan resource surcharge	1,116	948	18	4,327	2,334	85
Freehold and GORR	4,565	2,106	117	13,080	4,711	178
	8,730	4,634	88	24,754	10,615	133
Percent of total revenue	9.9%	9.2%	8	9.6%	8.9%	8
Per boe ($)	8.89	8.86	-	8.93	7.85	14

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and Saskatchewan resource surcharge. Royalties increased to $8.7 million in the third quarter of 2014 from $4.6 million in the third quarter of 2013 primarily, as a result of an 88 percent increase in production volumes.

During the nine months ended September 30, 2014, royalties increased 133 percent to $24.8 million from $10.6 million in the comparable period. The increase is primarily a result of a combination of 105 percent increase in production volumes and a 5 percent increase in commodity pricing.

Royalties as a percentage of revenue have increased slightly in both the three and nine month periods ended September 30, 2014 as a larger percentage of wells having freehold royalties were drilled in 2014.

Operating Expenses

	Three months ended September 30,		Percent	Nine months ended September 30,		Percent
	2014	2013	Change	2014	2013	Change
Total operating costs ($000's)	11,541	6,545	76	33,445	17,100	96
Percent of total revenue	13.0%	13.0%	-	13.0%	14.3%	(9)
Per boe ($)	11.75	12.53	(6)	12.07	12.64	(5)

Operating expenses increased to $11.5 million in the third quarter of 2014 from $6.5 million in the third quarter of 2013. The increase is attributable to the 88 percent increase in production volumes. During the nine months ended September 30, 2014, operating expenses increased 96 percent to $33.4 million from $17.1 million in the comparable period. The increase is a result of a 105 percent increase in production volumes.

Operating costs averaged $11.75/boe in the third quarter of 2014 and $12.07/boe in the year to date. This represents a decrease of 6 percent or $0.78/boe from $12.53/boe in the third quarter of 2013 and a decrease of 5 percent or $0.57/boe from the nine months ended September 30, 2013. Operating costs per boe decreased in both the three and nine month periods ended September 30, 2014, due to a component of operating costs being fixed as well as achieving operating efficiencies from focused operations in our core area.

Transportation Expenses

	Three months ended September 30,		Percent	Nine months ended September 30,		Percent
	2014	2013	Change	2014	2013	Change
Total transportation costs ($000's)	1,912	1,053	82	5,485	2,901	89
Percent of total revenue	2.2%	2.1%	5	2.1%	2.4%	(13)
Per boe ($)	1.95	2.02	(3)	1.98	2.15	(8)

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs increased to $1.9 million in the third quarter of 2014 from $1.1 million in the third quarter of 2013 as a result of an 88 percent increase in production volumes. During the nine month ended period September 30, 2014, transportation costs increased 89 percent to $5.5 million from $2.9 million in the comparable period. The increase is primarily a result of a 105 percent increase in production volumes.

Transportation costs averaged $1.95/boe in the third quarter of 2014 and $1.98/boe in the year to date. This is a decrease of 3 percent from $2.02/boe in the third quarter of 2013 and a decrease of 8 percent from the nine months ended September 30, 2013. Transportation costs per boe decreased in both the three and nine month periods ended September 30, 2014, due to a larger portion of our clean oil being transported by pipeline, which has a lower cost per boe, as well as focusing on streamlining trucking clean oil to the point of sale.

General and Administrative ("G&A") Expenses

	Three months ended September 30, 2014	2013	Percent Change	Nine months ended September 30, 2014	2013	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	2,003	1,423	41	6,056	3,973	52
Overhead recoveries	(139)	(168)	(17)	(561)	(629)	(11)
Capitalized G&A	(495)	(289)	71	(1,535)	(787)	95
	1,369	966	42	3,960	2,557	55
Percent of total revenue	1.5%	1.9%	(21)	1.5%	2.1%	(29)
Per boe ($)	1.39	1.85	(25)	1.43	1.89	(24)

The Company incurred gross G&A expenses of $2.0 million and $6.1 million, respectively, during the three and nine month periods ended September 30, 2014. Increased G&A costs before recoveries and capitalization were mainly the result of increased employee related costs including salaries, office rent and software driven by the capital growth of Raging River and its operations. Higher salary costs were driven by increased personnel including technical, operations and administrative staff.

Net G&A expenses incurred were $1.4 million or $1.39 per boe and $4.0 million or $1.43 per boe, respectively, during the three and nine month periods ended September 30, 2014. The decrease in net G&A per boe from the comparable periods is a result of G&A efficiencies achieved with higher production levels. In addition, capitalized G&A increased in both the three and nine month periods ended September 30, 2014, due to increased capital expenditures from a continued robust capital program.

Financial Charges

	Three months ended September 30, 2014	2013	Percent Change	Nine months ended September 30, 2014	2013	Percent Change
Financial charges ($000's)	894	169	429	2,879	553	421
Percent of total revenue	1.0%	0.3%	233	1.1%	0.5%	120
Per boe ($)	0.91	0.32	184	1.04	0.41	154

Financial charges during the three and nine month periods ended September 30, 2014, were $894 thousand and $2.9 million respectively compared to $169 thousand and $553 thousand respectively for 2013. Interest on bank debt increased in both the three and nine month periods ended September 30, 2014, due to carrying higher average debt levels throughout 2014 as compared to 2013, to fund operations and significant capital spending. Standby charges increased during both the third quarter of 2014 and year to date as a result of an increase in the authorized borrowing base to $300 million compared to the borrowing base of $125 million in the third quarter of 2013. As at September 30, 2014 the Company had drawn $30.5 million against the available credit facility.

Stock-based Compensation

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	Percent Change	2014	2013	Percent Change
Stock based compensation ($000's)	1,463	641	128	3,324	1,566	112
Percent of total revenue	1.7%	1.3%	31	1.3%	1.3%	-
Per boe ($)	1.49	1.23	21	1.20	1.16	3

As at September 30, 2014, the Company has issued a total of 12.9 million stock options with a weighted average fair value of $2.41 per option. Stock based compensation expense in the third quarter of 2014 was $1.5 million compared to $641 thousand in the third quarter of 2013. Stock based compensation expense increased in the third quarter and year to date of 2014, due to the increase in the fair value of stock options granted in 2014 arising from Raging River's increase in share price combined with additional options granted.

The expense is driven by the timing and valuation of new stock option grants. Stock options granted have a term of 3.5 years to expiry and have a three year vesting period from the date of grant. The stock-based compensation plan is accounted for using the fair value method of accounting.

Depletion, Depreciation and Accretion

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	Percent Change	2014	2013	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion and depreciation	22,834	14,369	59	64,222	37,573	71
Exploration and evaluation lease expiries	-	-	-	581	1,185	(51)
Accretion	198	89	122	523	245	113
	23,032	14,458	59	65,326	39,003	67
Percent of total revenue	26.0%	28.7%	(9)	25.3%	32.6%	(22)
Per boe ($) – Depletion and depreciation	23.44	27.67	(15)	23.36	27.96	(16)
Per boe ($) – Exploration and evaluation lease expiries	-	-	-	0.21	0.88	(76)

Depletion of oil and gas assets is provided on the "unit-of–production" method based on total proved and probable reserves, including future development costs, on a component basis. Depletion and depreciation expense increased to $22.8 million and $64.2 million respectively for the three and nine month periods ended September 30, 2014. The increase in depletion expense is a result of an increase in production volumes and capital base from capital expenditures from an intensive drilling program. The per boe depletion and depreciation rate declined for both the three and nine month periods ended September 30, 2014, due to significant reserve additions recorded in the fourth quarter of 2013 that more than offset the increase in production in each of the current periods.

Accretion increased in the third quarter of 2014 to $198 thousand from $89 thousand in the comparable quarter of 2013. This increase is primarily due to the increase in asset retirement obligation from drilling and acquisition activities. Accretion represents the time value of the asset retirement obligation and is calculated at the Company's risk-free rate, currently 2.72 percent. It will continue to increase with the passage of time and the increases in asset retirement obligations.

During the nine month period ended September 30, 2014, $581 thousand of costs associated with expired mineral leases were recognized as depletion expense in the statement of comprehensive earnings. In comparison, $1.2 million of lease expiries were recorded for the nine months ended September 30, 2013.

Asset Retirement Obligations

As at September 30, 2014, the asset retirement obligation of the Company was $33.5 million. The Company recorded an increase of $13.9 million in the obligation from the asset retirement obligation of $19.6 million as at December 31, 2013. This is related to the capital exploration and development program in 2014, an upward revision to the estimate due to discounting the costs at a lower risk-free rate at September 30, 2014 relative to the rate applied at December 31, 2013 and an increase to the underlying cost estimates.

Income Taxes

In the nine month period ended September 30, 2014, Raging River recorded $20.1 million of current tax expense and $11.9 million of deferred income taxes for total income taxes of $32.0 million. The Company's effective tax provision rate is 27 percent.

In the three month period ended September 30, 2014, the Company recorded a current tax expense of $6.4 million and deferred income taxes of $5.3 million.

Funds from Operations and Net Earnings

The Company's funds from operations and net earnings generating capability are a direct result of production, commodity prices, and the cost to find and produce reserves. In the nine month period of operations ended September 30, 2014, Raging River recorded funds from operations of $164 million and net earnings of $86.1 million. This is a significant increase from the 2013 results with funds from operations of $81.1 million and net earnings of $26.8 million, due primarily to increased production volumes, lower operating costs per boe, lower depletion rates per boe and higher commodity prices for the majority of 2014.

The following table summarizes the operating netback, funds from operations and net earnings on a barrel of oil equivalent basis:

	Three months ended September 30, 2014	2013	Percent Change	Nine months ended September 30, 2014	2013	Percent Change
	($/boe)			*($/boe)*		
Petroleum and natural gas revenue	90.14	96.25	(6)	93.17	88.51	5
Realized gain (loss) on commodity contracts	0.13	(7.65)	(102)	(1.31)	(3.06)	(57)
Royalties	(8.89)	(8.86)	-	(8.93)	(7.85)	14
Net revenue	81.38	79.74	2	82.93	77.60	7
Operating expenses	(11.75)	(12.53)	(6)	(12.07)	(12.64)	(5)
Transportation expenses	(1.95)	(2.02)	(3)	(1.98)	(2.15)	(8)
Operating netback	67.68	65.19	4	68.88	62.81	10
General and administrative expenses	(1.39)	(1.85)	(25)	(1.43)	(1.89)	(24)
Financial charges	(0.91)	(0.32)	184	(1.04)	(0.41)	154
Current taxes	(6.51)	(1.44)	352	(7.25)	(0.55)	1,218
Funds from operations	58.87	61.58	(4)	59.16	59.96	(1)
Unrealized gain (loss) on financial instruments	3.51	(3.57)	(198)	0.98	(3.30)	(130)
Stock-based compensation expense	(1.49)	(1.23)	21	(1.20)	(1.16)	3
Exploration and evaluation lease expiries	-	-	-	(0.21)	(0.88)	(76)
Depletion, depreciation and accretion expense	(23.44)	(27.67)	(15)	(23.36)	(27.96)	(16)
Earnings before deferred taxes	37.45	29.11	29	35.37	26.66	33
Deferred income tax provision	(5.39)	(6.65)	(19)	(4.29)	(6.84)	(37)
Net earnings	32.06	22.46	43	31.08	19.82	57

Capital Expenditures

Total exploration and development capital expenditures for the three and nine month periods ended September 30, 2014, were $81.7 million and $181.5 million respectively, compared to $60.2 million and $108.4 million for the same periods in 2013. The expenditures are detailed below:

	Three months ended September 30, 2014	2013	Percent Change	Nine months ended September 30, 2014	2013	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Land	348	366	(5)	2,141	2,278	(6)
Property acquisitions	4,763	-	100	4,763	1,047	355
Geological and geophysical	17	69	(75)	94	209	(55)
Drilling and completions	71,773	58,569	23	161,255	101,578	59
Production facilities	4,707	1,178	300	13,116	3,256	303
Other	56	2	2,700	102	5	1,940
Exploration and development	81,664	60,184	36	181,471	108,373	67

In the nine months period ended September 30, 2014, Raging River drilled a total of 185 (157.9 net) crude oil wells, primarily in the greater Dodsland area in southwest Saskatchewan, with a 99 percent success rate. This included 182 (155.9 net) crude oil wells, 1 (0.5 net) stratigraphic test well and 2 (1.5 net) dry holes. 3 (3.0 net) wells drilled and completed in the first quarter of 2014 have been deemed to be below the current internally calculated economic threshold.

In the third quarter of 2014, Raging River drilled a total of 87 (69.7 net) crude oil wells including 85 (68.7 net) horizontal crude oil wells, 1 (0.5 net) strategic test well and 1 (0.5 net) abandoned well for a success rate of 99%. By comparison, the Company drilled a total of 94 (71.1 net) wells in the third quarter of 2013 and 144 (113.3 net) wells in the nine month period ended September 30, 2013.

During the third quarter, Raging River invested a total of $81.7 million on capital expenditures including $76.5 on drilling, completion and production facilities and $5.1 million on land and property acquisitions. The property acquisitions included approximately 30 bbls/d of oil and 12,000 net acres of land prospective for Viking oil.

During the nine months period ended September 30, 2014, the Company spent $181.5 million on capital expenditures including $174.4 million on drilling, completions and production facilities and $6.9 million on land and property acquisitions.

On November 6, 2014, the capital budget was expanded to $275 million from $260 million. It is anticipated that this budget will be funded from 2014 cash flow combined with the Company's syndicated credit facility of $300 million.

Drilling Activity

The following table summarizes our drilling results:

	Three months ended September 30,				Nine months ended September 30,			
	2014		2013		2014		2013	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil	85	68.7	94	71.1	182	155.9	143	112.3
Natural gas	-	-	-	-	-	-	-	-
Test well	1	0.5	-	-	1	0.5	1	1
Service	-	-	-	-	-	-	-	-
Dry and abandoned	1	0.5	-	-	2	1.5	-	-
Total	87	69.7	94	71.1	185	157.9	144	113.3
Success (1)	99%	99%	100%	100%	99%	99%	100%	100%

(1) The Company does not include test wells in the calculation of success. Although 100% of the wells drilled in the first quarter of 2014 were drilled, completed and placed on production, 3 (3.0 net) wells have been deemed to be below an internally calculated economic threshold.

Liquidity and Capital Resources

At September 30, 2014, the Company had net debt of $113 million compared to net debt of $96.3 million at December 31, 2013. For the nine months period ended September 30, 2014, funds from operations of $164 million combined with warrant proceeds of $0.8 million less capital expenditures of $181.5 million resulted in the ending net debt of $113 million. The Company expects to have adequate liquidity to fund the updated 2014 capital expenditure budget of $275 million through a combination of funds flow from operations, and the $300 million syndicated credit facility. Raging River anticipates that it will make use of additional bank debt or equity financing for any substantial expansion in its capital program or to finance any significant acquisitions.

Capital Resources

	September 30, 2014	September 30, 2013
($ thousands)		
Capital Resources		
Bank debt available	300,000	125,000
Working capital deficiency	113,026	(42,446)
Total capital resources available	186,974	82,554

The Company currently has warrants outstanding that entitle the holders to purchase common shares at an exercise price of $2.00 per common share until March 15, 2015. During the three months ended March 31, 2014, the Company amended the terms of the warrants to allow warrants to be exercised on a “cash-less” basis by surrendering the warrants in exchange for the issuance of common shares equal to the number determined by dividing the closing price of the common shares on the Toronto Stock Exchange (“TSX”) on the trading day immediately preceding the date of exercise into the difference between the market price and the exercise price of the warrants.

During the year ended December 31, 2013, the Company amended its Option Plan to allow options to be exercised on a “cash-less” basis by surrendering the options in exchange for the issuance of common shares equal to the number determined by dividing the closing price of the common shares on the TSX on the date of exercise into the difference between the closing price and the exercise price of the options being exercised.

Changes to share capital were the following:

During the nine months period ended September 30, 2014, 1.1 million stock options were exercised for 783 thousand common shares on a cash-less basis.

During the nine months period ended September 30, 2014, 11.2 million warrants were exercised for 8.1 million common shares on a cash-less basis.

During the nine months period ended September 30, 2014, 410 thousand warrants were exercised for 410 thousand common shares for proceeds of $820 thousand.

Common share information

CAPITALIZATION

Share Capital

	Three months ended September 30,		Nine months ended September 30,	
Outstanding common shares	2014	2013	2014	2013
Weighted average outstanding common shares (1)				
-Basic	180,081	156,757	178,343	156,757
-Diluted	188,442	169,485	186,375	167,186
Outstanding securities at September 30, 2014				
-Common shares				180,208,989
-Common share options – average strike price of $4.98				12,928,738
-Warrants issued through Private Placement – strike price of $2.00				2,617,422

(1) Diluted weighted average share information reflects the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted weighted average share information is calculated assuming that any proceeds received by the Company upon exercise of in-the-money stock options or warrants plus the unamortized stock compensation expense would be used to buy back common shares at the average market price for the period.

Total Market Capitalization

The Company's market capitalization at September 30, 2014 was $1.7 billion.

	September 30, 2014
Common shares outstanding	180,208,989
Share price [(1)]	$9.17
Total market capitalization	$1,652,516

(1) Represents the last price traded on the TSX on September 30, 2014.

As at November 6, 2014 the Company had 180,213,989 common shares outstanding.

	November 6, 2014
Outstanding securities at November 6, 2014	
-Common shares	180,213,989
-Stock options – weighted average exercise price of $5.01	13,028,738
-Warrants issued through Private Placement	2,612,422

Subsequent Events

On November 6, 2014, the board of directors approved a capital budget increase to $275 million from $260 million.

Contractual Obligations and Commitments

Raging River has assumed various contractual obligations and commitments in the normal course of operations and financing activities. We consider these obligations when assessing cash requirements in the discussion of future liquidity that follows:

Contractual Obligations

Payments due by Period ($ thousands)	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years	Total
Office Lease	724	2,171	664	-	3,559
Bank debt	-	30,523	-	-	30,523
Total contractual obligations	724	32,694	664	-	34,082

Off-Balance Sheet Arrangements

There are currently no significant off-balance sheet arrangements.

Related Party Transactions

The Company did not have any related party transactions in the nine months ended September 30, 2014.

Summary of Quarterly Results

	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13	Q1/13	Q4/12
Financial *(thousands of dollars except share data)*								
Petroleum and natural gas revenue	88,566	88,931	80,707	56,106	50,287	36,264	33,151	21,764
Funds flow from operations [1]	57,850	56,283	49,813	35,882	32,174	25,527	23,383	15,089
Per share - basic	0.32	0.32	0.28	0.22	0.21	0.16	0.15	0.12
- diluted	0.31	0.30	0.27	0.20	0.19	0.15	0.14	0.12
Net earnings	31,505	30,238	24,360	16,622	11,738	8,810	6,241	4,943
Per share - basic	0.17	0.17	0.14	0.10	0.07	0.06	0.04	0.04
- diluted	0.17	0.16	0.13	0.09	0.07	0.05	0.04	0.03
Capital expenditures, net	81,664	27,789	72,017	164,121	60,184	10,583	37,608	62,209
Capital expenditures – corporate	-	-	-	-	-	-	-	5,211
Shareholders' equity	470,775	437,159	405,258	379,403	286,318	273,703	264,027	257,371
Weighted average shares *(thousands)*								
Basic	180,081	179,438	175,461	164,121	156,757	156,757	156,757	127,149
Diluted	188,442	188,002	183,417	178,729	169,485	166,546	164,775	129,380
Shares outstanding, end of period *(thousands)*								
Basic	180,209	179,890	179,213	170,914	156,757	156,757	156,757	156,757
Diluted	195,755	195,104	192,372	195,214	180,879	180,829	177,672	177,372
Operating *(6:1 boe conversion)*								
Average daily production								
Crude oil and NGLs *(bbls/d)*	10,278	9,500	9,427	7,458	5,495	4,387	4,454	3,027
Natural gas *(mcf/d)*	2,406	2,765	2,269	1,912	1,104	1,401	580	618
Barrels of oil equivalent [2] *(boe/d)*	10,679	9,960	9,805	7,777	5,679	4,620	4,550	3,130
Average selling prices[4]								
Crude oil and NGLs *($/bbl)*	92.79	101.59	93.75	80.93	98.98	89.71	82.29	77.54
Natural gas *($/mcf)*	3.74	4.41	5.69	3.28	2.43	3.55	3.18	3.05
Barrels of oil equivalent [2] *($/boe)*	90.14	98.11	91.46	78.42	96.25	86.26	80.95	75.59
Netbacks ($/boe)								
Operating								
Petroleum and natural gas revenue[4]	90.14	98.11	91.46	78.42	96.25	86.26	80.95	75.59
Realized gain (loss) on commodity contracts	0.13	(2.34)	(1.86)	(1.99)	(7.65)	(0.49)	0.15	0.83
Royalties	(8.89)	(9.63)	(8.27)	(7.02)	(8.86)	(7.46)	(6.94)	(6.69)
Operating expenses	(11.75)	(11.99)	(12.50)	(12.42)	(12.53)	(12.78)	(12.66)	(12.44)
Transportation expenses	(1.95)	(1.99)	(2.01)	(2.10)	(2.02)	(2.25)	(2.20)	(1.75)
Operating netback *($/boe)*	67.68	72.16	66.82	54.89	65.19	63.28	59.30	55.54
General and administrative	(1.39)	(1.43)	(1.47)	(1.78)	(1.85)	(1.95)	(1.88)	(2.31)
Financial charges	(0.91)	(1.19)	(1.03)	(0.76)	(0.32)	(0.61)	(0.32)	(0.79)
Asset retirement obligation	-	-	-	-	-	-	-	(0.03)
Current taxes	(6.51)	(7.45)	(7.88)	(2.20)	(0.55)	-	-	-
Funds flow netback[3] *($/boe)*	58.87	62.09	56.44	50.15	62.47	60.72	57.10	52.41

(1) Management uses funds flow from operations to analyze operating performance and leverage. Funds flow from operations as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities. The reconciliation between funds flow from operations and cash flow from operating activities can be found in this MD&A.
(2) Boe conversion ratio for natural gas of 1 Boe: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil 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.
(3) Funds flow netbacks are calculated as the operating netback less general and administrative expenses, financial charges asset retirement obligations, transaction costs and current taxes.
(4) Excludes unrealized risk management contracts.

The fluctuations in Raging River's revenue, funds flow from operations and net earnings from quarter to quarter are primarily due to increases in production volumes, changes in realized commodity pricing and the related impact on royalties. With the commencement of operations in the latter part of the first quarter of 2012, and continuing through into 2014, the Company has maintained an active capital expenditure program combined with property acquisitions and corporate acquisitions. This has resulted in a substantial increase on a quarter over quarter basis in the Company's 2014 production, revenues, funds from operations and net earnings. Please refer to the Financial and Operating Results section of this MD&A for detailed discussions of changes in the third quarter of 2014.

Business Environment and Risk

The business risks the Company is exposed to are those inherent in the oil and gas industry as well as those governed by the individual nature of Raging River's operations. Geological and engineering risks, the uncertainty of discovering commercial quantities of new reserves, commodity prices, interest rate and foreign exchange risks, competition and government regulations – all of these govern the business and influence the controls and management at the Company. Raging River manages these risks by:

- attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Company;
- operating properties in order to maximize opportunities;
- employing risk management instruments to minimize exposure to volatility of commodity prices, interest rate and foreign exchange rates;
- maintaining a strong financial position; and
- maintaining strict environmental, safety and health practices

For additional details on the risks relating to Raging River's business, see "Risk Factors" in the Company's most recent annual information form, which is available on SEDAR at www.sedar.com.

Disclosure Controls and Procedures

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

Internal Controls over Financial Reporting

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No changes were made to the Company's internal controls over financial reporting during the period from July 1, 2014 to September 30, 2014 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

It should be noted that while Raging River's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and that they are effective, they do not expect that these controls will prevent all errors or fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Application of Critical Accounting Estimates

Use of estimates and judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur.

Estimates and their underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and for any future years affected.

a) Critical Judgments in Applying Accounting Policies

The determination of what constitutes a cash-generating unit ("CGU") used to test the recoverability of development and production asset carrying values is subject to management judgment. Judgments are made in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality. The asset composition of a CGU can directly impact the recoverability of the assets included therein. The key estimates used in the determination of cash flows from oil and natural gas reserves include the following:

i) Reserves – assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production levels or results of future drilling may change the economic status of reserves and may ultimately result in reserves being restated.

ii) Oil and natural gas prices – forward price estimates are used in the cash flow model. Commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchanges rates, weather, and economic and geopolitical factors.

iii) Discount rate – the discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

b) Key Sources of Estimation Uncertainty

Amounts recorded for depletion and depreciation and amounts used for impairment calculations are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates, future development costs and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the financial statements in future periods could be material.

Amounts recorded for asset retirement obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of abandonment expenditures. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.

The estimated fair values of derivative financial instruments resulting in financial assets and liabilities, by their very nature are subject to measurement uncertainty.

The estimated fair values of stock options and warrants using pricing models such as the Black-Scholes model is based on significant assumptions such as volatility and expected term.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty.

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events

Summary of Significant Accounting Policies

The Company's accounting policies are described in Note 3 to the December 31, 2013 audited annual financial statements, except as noted below. Those accounting policies have been applied consistently to all periods presented in the Company's interim financial statements.

Effective January 1, 2014, the Company retrospectively adopted International Financial Reporting Interpretation Committee ("IFRIC") 21 Levies. IFRIC 21 clarified that an entity recognizes a liability for a levy when the activity that triggers payment occurs. For a levy that is triggered upon reaching a minimum threshold, the interpretation clarified that no liability should be anticipated before the minimum threshold is reached. The adoption of this interpretation did not have an impact on the Company's financial statements.

Future accounting pronouncements

The IASB has undertaken a three-phase project to replace IAS 39 "Financial Instruments: Recognition and Measurement" with IFRS 9 "Financial Instruments." In November 2009, the IASB issued the first phase of IFRS 9, which details the classification and measurement requirements for financial assets. Requirements for financial liabilities were added to the standard in October 2010. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. In November 2013, the IASB issued the third phase of IFRS 9, which details the new general hedge accounting model. Hedge accounting remains optional and the new model is intended to allow reporting issuers to better reflect risk management activities in the financial statements and provide more opportunities to apply hedge accounting. The Company does not employ hedge accounting for its current risk management contracts. The IASB tentatively decided that IFRS 9 would be mandatorily effective for annual periods beginning on or after January 1, 2018. The full impact of the standard on the Company's financial statements will not be known until the project is complete.

Corporate Information

Board of Directors

NEIL ROSZELL
President & CEO, Raging River Exploration Inc.
Calgary, Alberta

GARY BUGEAUD (2)
Businessman
Calgary, Alberta

GEORGE FINK (1) (2)
Chairman & CEO, Bonterra Energy Corp.
Calgary, Alberta

RAYMOND P. MACK (1) (3)
Partner, Kenway Mack Slusarchuk Stewart LLP
Calgary, Alberta

KEVIN OLSON (1) (3)
President, Kyklopes Capital Management Ltd.
Calgary, Alberta

DAVE PEARCE (2) (3)
Deputy Managing Partner, KERN Partners
Calgary, Alberta

(1) Audit Committee
(2) Corporate Governance and Compensation Committee
(3) Reserves Committee

Officers

NEIL ROSZELL, P. Eng.
President & CEO

BRUCE ROBERTSON
Executive Vice President

JERRY SAPIEHA, CA
Vice President Finance & CFO

BRUCE BEYNON
Vice President Exploration

JASON JASKELA, P. Eng.
Vice President Production & COO

TERRY DANKU
Vice President Engineering

SCOTT RIDEOUT
Vice President Land

TED BROWN (Corporate Secretary)
Burnet, Duckworth & Palmer LLP

Head Office
Suite 1700, 605 – 5th Avenue SW
Calgary, Alberta T2P 3H5
Tel: (403) 387-2950
Fax: (403) 387-2951

Auditors
KPMG LLP
Calgary, Alberta

Independent Reservoir Consultants
Sproule Associates Limited
Calgary, Alberta

Website: www.rrexploration.com