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 14, 2013 and should be read in conjunction with the unaudited interim financial statements for the three and nine months ended September 30, 2013 and the audited consolidated financial statements for the period ended December 31, 2012, the notes thereto and the related management discussion and analysis. The interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are referenced in Canadian dollars, except when noted otherwise.

Forward Looking Statements

This MD&A (as defined below) may include forward-looking statements including opinions, assumptions, estimates and management's assessment of future plans and operations, expected royalty rates, and drilling royalty credits on the Company, plans to monitor operating and capital expenditures and to adjust capital spending if required, expectations as to the non-taxability of the Company 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 factors 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, which are available on SEDAR at www.sedar.com. Statements relating to "reserves" 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. Expect as required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements.

Additional GAAP Measures

The Management's Discussion and Analysis ("MD&A") contains the term funds 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 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,	
	2013	2012	2013	2012
Cash flow from operating activities	28,444	9,750	66,858	12,998
Changes in non – cash working capital	3,730	519	14,226	5,711
Funds flow from operations	32,174	10,269	81,084	18,709

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

Non-GAAP Measures

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 and working capital deficiency, which terms represent 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 six 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, 2012 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.

Raging River commenced active operations on March 16, 2012 following the completion of the Plan of Arrangement among Wild Stream Exploration Inc., Crescent Point Energy Corp. and the Company. Upon completion of the Plan of Arrangement, Wild Stream shareholders received 1.0 Raging River common share, 0.17 Crescent Point common share and 0.2 of a Raging River purchase warrant. Concurrent with the arrangement Raging River acquired certain oil-weighted assets (the "Acquired Assets") in the Dodsland area in southwest Saskatchewan. The Acquired Assets were purchased with an effective date of January 1, 2012 and a closing date of March 15, 2012.

Accordingly the operations below for the comparative period reflect only a 198 day period in the nine month period ended September 30, 2012.

Corporate Highlights

THIRD QUARTER 2013 HIGHLIGHTS

- Achieved record quarterly production of 5,679 boe/d weighted 95% to oil. This represents an increase of 167% over the comparable period in 2012 and a 23% increase from the second quarter of 2013.

- Achieved our previous increased exit guidance of 6,300 boe/d at the end of September having only spent 75% of the then planned $145 million development budget.

- Executed an aggressive $60.2 million capital program to drill 94 (71.1 net) Viking horizontal oil wells at a 100% success rate.

- Generated record operating and corporate netbacks of $65.19/boe and $63.02/boe. Combined with record production levels, the netbacks resulted in a quarter over quarter 26% increase to cash flow to $32.2 million ($0.21 per share – basic).

- Maintained balance sheet strength with third quarter exit net debt of $42.4 million, representing 0.3 times debt to third quarter annualized cash flow.

HIGHLIGHTS FOR RAGING RIVER SUBSEQUENT TO THE THIRD QUARTER OF 2013 INCLUDE:

- Increased our 2013 annual and exit production guidance for the fourth time to 5,400 boe/d and 8,000 boe/d respectively.

- As disclosed previously, the Company entered into agreements to acquire Viking light oil assets consisting of 900 boe/d (85% light oil) and 40.3 net sections of highly prospective land targeting Viking oil for total consideration of approximately $105 million.

- On November 13, 2013 closed a $78.4 million bought deal financing, issuing 14 million common shares at a price of $5.60 per share.

- Increased our capital budget from $145 million to $270 million including $105 million allocated to the above acquisition and $165 million allocated to development activities.

Petroleum and Natural Gas Revenue

	Three months ended September 30, 2013	2012	Percent Change	Nine months ended September 30, 2013	2012	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Liquids revenue	50,033	14,976	234	118,819	28,096	323
Natural gas revenue	246	56	339	865	96	801
Royalty revenue	8	6	33	18	8	125
	50,287	15,038	234	119,702	28,200	324
Operating: (6:1 boe conversion)						
Average daily production						
Liquids (bbls/d)	5,495	2,073	165	4,782	1,831	161
Natural gas (mcf/d)	1,104	319	246	1,030	293	252
Barrels of oil equivalent (boe/d)	5,679	2,127	167	4,954	1,880	164
Average Raging River sales price						
Liquids ($/bbl)	98.98	78.54	26	91.03	77.50	17
Natural gas ($/mcf)	2.43	1.91	27	3.08	1.65	86
Barrel of oil equivalent ($/boe)	96.25	76.86	25	88.51	75.74	17
Average Benchmark Prices						
Crude Oil - WTI (US$/bbl)	105.82	92.18	15	98.15	96.16	2
Crude Oil - Edmonton Par	105.17	84.79	24	95.57	87.29	9
Natural gas - AECO	2.43	2.20	10	3.00	2.22	35
Exchange rate (US$/Cdn$)	0.96	0.99	(3)	0.98	1.00	(2)

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 Edmonton par light, sweet oil. The WTI price increased significantly in the third quarter to US$105.82/bbl from US$92.18/bbl in the comparable period of 2012. As a result of the increase in WTI and the narrowing discount between the Edmonton Light Par price relative to WTI, the Company's average realized price for oil sales increased in both the three and nine month periods ended September 30, 2013. Raging River's average quality adjustment to Edmonton Par pricing during the third quarter of 2013 was $6.19/bbl compared to $6.25/bbl in the third quarter of 2012. The Company's liquids price averaged $98.98/bbl for the third quarter of 2013, up 26% compared to $78.54/bbl in the third quarter of 2012. Similarly, Raging River's average quality adjustment to Edmonton Par pricing decreased in the nine months period ended September 30, 2013 to $4.54/bbl from $9.79/bbl in the comparable period of 2012. The Company's liquids price averaged $91.03 per boe in the nine month period ended September 30, 2013, up 17% from the average price of $77.50/bbl received in the comparable period of 2012. Raging River's realized natural gas price in the third quarter of 2013 was $2.43 per mcf compared to the AECO daily index average of $2.43.

Both the WTI and Edmonton par price increased significantly in the third quarter of 2013 from the comparable period of 2012 that contributed to the increase in Raging River's realized prices.

During the third quarter of 2013, the Company drilled a total of 94 gross (71.1 net) wells with a 100% success rate, all in the greater Dodsland area in southwest Saskatchewan.

Production	Q3/13	Q2/13	Q1/13	Q4/12	Q3/12	Q2/12	Q1/12
Production							
Liquids (bbls/d)	5,495	4,387	4,454	3,027	2,073	1,667	1,345
Natural gas (mcf/d)	1,104	1,401	580	618	319	268	291
Total (boe/d)	5,679	4,620	4,550	3,130	2,127	1,711	1,394
% increase over prior quarter	23%	2%	45%	47%	24%	23%	-

The Company's production for the third quarter of 2013 increased to 5,679 boe/d from 2,127 boe/d in the third quarter of 2012, an increase of 167 percent. Quarter over quarter, production in the third quarter of 2013 increased to 5,679 boe/d from 4,620 boe/d in the second quarter, an increase of 23 percent. The year over year increase was primarily attributable to a successful drilling program in 2013 and 2012.

Petroleum and natural gas revenue in the three month period September 30, 2013 was $50.3 million as compared to $15.0 million in the comparable period of 2012. This increase was attributable to a combination of a 167 percent increase in production volumes and by a 25 percent increase in commodity pricing.

Revenues for the nine months ended September 30, 2013 were $119.7 million, as compared to $28.2 million for the nine months period ended September 30, 2012, representing an increase of $91.5 million or 324 percent. This increase in revenue is again attributed to a combination of a 164 percent increase in production volumes and a 17 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 14, 2013 the Company has the following price contracts in place by quarter:

2013

Q4

Crude oil	Fixed	Oct 2013 – Dec 2013	2,600 bbls/d	Cdn $97.05	WTI
Crude oil	Collar	Oct 2013 – Dec 2013	200 bbls/d	USD $95.00 - $104.25	WTI
Crude oil	Collar	Oct 2013 – Dec 2013	200 bbls/d	Cdn $90.00 - $102.00	WTI
Natural gas	Fixed	Oct 2013 – Dec 2013	500 GJs/d	Cdn $3.28/GJ	AECO

2014

Q1

Crude oil	Fixed	Jan 2014 – Mar 2014	1,200 bbls/d	Cdn $96.86/bbl	WTI

Q2

Crude oil	Fixed	Apr 2014 – Jun 2014	800 bbls/d	Cdn $97.37/bbl	WTI

Q3

Crude oil	Fixed	Jul 2014 – Sept 2014	200 bbls/d	Cdn $97.24/bbl	WTI

Q4

Crude oil	Fixed	Oct 2014 – Dec 2014	200 bbls/d	Cdn $95.82/bbl	WTI

Realized & unrealized gain on financial instruments

For the nine months ended September 30, 2013, the Company realized losses of $4.1 million. The realized loss represents the commodity contracts settled during the nine months ended September 30, 2013. Due to a volatile WTI in the third quarter of 2013, the Company recorded a realized loss of $4.0 million, compared to a realized gain of $7 thousand in the comparable period of 2012.

As of September 30, 2013, the fair value of Raging River's outstanding commodity contracts is an unrealized liability of $4.1 million as reflected in the 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, 2013 had the contracts been monetized or terminated. Subsequent changes in the fair value of the commodity contracts are recognized in the financial statements and could be materially different than what is recorded at September 30, 2013. The unrealized loss of $4.5 million represents the fair value change of the underlying commodity contracts to be settled in the future.

Royalties

	Three months ended September 30, 2013	Three months ended September 30, 2012	Percent Change	Nine months ended September 30, 2013	Nine months ended September 30, 2012	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Crown	1,580	684	131	3,570	1,320	170
Saskatchewan resource surcharge	948	321	195	2,334	571	309
Freehold and GORR	2,106	501	320	4,711	977	382
	4,634	1,506	208	10,615	2,868	270
Percent of total revenue	9.2%	10.0%	(8)	8.9%	10.2%	(13)
Per boe ($)	8.86	7.70	15	7.85	7.70	2

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and Saskatchewan resource surcharge. Royalties increased to $4.6 million in the third quarter of 2013 from $1.5 million in the third quarter of 2012 primarily as a result of a combination of 167 percent increase in production volumes and a 25 percent increase in commodity pricing.

During the nine months ended September 30, 2013 royalties increased 270 percent to $10.6 million from $2.9 million in the comparable period. The increase is primarily a result of a combination of 164 percent increase in production volumes and a 17 percent increase in commodity pricing.

Royalties as a percentage of revenue have decreased in both the three and nine month period ended September 30, 2013 due to increased oil production from new drills in Saskatchewan that qualified for crown royalty incentives. The Company's average royalty rate is expected to increase to approximately 9.5% in the fourth quarter of 2013 as a larger percentage of wells having freehold royalties will be drilled in the fourth quarter of 2013.

Operating Expenses

	Three months ended September 30, 2013	Three months ended September 30, 2012	Percent Change	Nine months ended September 30, 2013	Nine months ended September 30, 2012	Percent Change
Total operating costs ($000's)	6,545	2,354	178	17,100	4,880	250
Percent of total revenue	13.0%	15.7%	(17)	14.3%	17.3%	(17)
Per boe ($)	12.53	12.03	4	12.64	13.11	(4)

Operating expenses increased to $6.5 million in the third quarter of 2013 from $2.4 million in the third quarter of 2012. The increase is attributable to the 167 percent increase in production volumes. Quarter over quarter per unit operating expenses decreased by $0.25 per boe primarily due to improved weather conditions that resulted in decreased fuel, road maintenance and emulsion trucking costs combined with operational efficiencies achieved.

During the nine months ended September 30, 2013 operating expenses increased 250 percent to $17.1 million from $4.9 million in the comparable period. The increase is primarily a result of a 164 percent increase in production volumes.

Transportation Expenses

	Three months ended September 30, 2013	Three months ended September 30, 2012	Percent Change	Nine months ended September 30, 2013	Nine months ended September 30, 2012	Percent Change
Total transportation costs ($000's)	1,053	330	219	2,901	642	352
Percent of total revenue	2.1%	2.2%	(5)	2.4%	2.3%	4
Per boe ($)	2.02	1.69	20	2.15	1.72	25

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs increased to $1.1 million in the third quarter from $330 thousand in the third quarter of 2012 as a result of a 167 percent increase in production volumes. On a per boe basis, transportation expenses for the third quarter increased to $2.02 per boe from $1.69 per boe primarily due to a larger portion of our clean oil being transported by truck rather than pipeline, which is a lower cost per boe.

During the nine months ended September 30, 2013 transportation costs increased 352 percent to $2.9 million from $642 thousand in the comparable period. The increase is primarily a result of a 164 percent increase in production volumes. On a per boe basis, transportation expenses increased to $2.15 per boe from $1.72 per boe.

General and Administrative ("G&A") Expenses

	Three months ended September 30, 2013	Three months ended September 30, 2012	Percent Change	Nine months ended September 30, 2013	Nine months ended September 30, 2012	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	1,423	934	52	3,973	1,868	113
Overhead recoveries	(168)	(272)	(38)	(629)	(330)	91
Capitalized G & A	(289)	(176)	64	(787)	(366)	115
	966	486	99	2,557	1,172	118
Percent of total revenue	1.9%	3.2%	(41)	2.1%	4.2%	(50)
Per boe ($)	1.85	2.48	(25)	1.89	3.15	(40)

The Company incurred gross G&A expenses of $1.4 million and $4.0 million, respectively, during the three and nine month periods ended September 30, 2013. Increased general and administrative costs before recoveries and capitalization were mainly the result of increased employee related costs including salaries and office rent driven by the capital growth of Raging River and its operations.

Net general and administrative expenses incurred were $966 or $1.85 per boe and $2.6 million or $1.89 per boe, respectively, during the three and nine month periods ended September 30, 2013. The decrease in net G&A per boe from the comparable periods is primarily due to increased production volumes from successful drilling activities. In addition, overhead recoveries and capitalized G&A increased in both the three and nine month periods ended due to a significant increase in capital expenditures.

Financial Charges

	Three months ended September 30, 2013	Three months ended September 30, 2012	Percent Change	Nine months ended September 30, 2013	Nine months ended September 30, 2012	Percent Change
Financial charges ($000's)	169	100	69	553	286	93
Percent of total revenue	0.3%	0.7%	(57)	0.5%	1.0%	(50)
Per boe ($)	0.32	0.51	(37)	0.41	0.77	(47)

Financial charges for the third quarter ended September 30, 2013 were $169 thousand or $0.32 per boe compared to $100 thousand or $0.51 per boe in the third quarter of 2012. Interest on bank debt increased in the third quarter due to carrying higher average debt levels throughout the quarter than in the third quarter of 2012. As at September 30, 2013 the Company had drawn $6.1 million against the available credit facility of $125 million.

Stock-based Compensation

	Three months ended September 30, 2013	Three months ended September 30, 2012	Percent Change	Nine months ended September 30, 2013	Nine months ended September 30, 2012	Percent Change
Stock based compensation ($000's)	641	270	137	1,566	388	304
Percent of total revenue	1.3%	1.8%	(27)	1.3%	1.4%	(7)
Per boe ($)	1.23	1.38	11	1.16	1.04	12

As at September 30, 2013 the Company has issued a total of 9.7 million stock options with a weighted average fair value of $0.72 per option. The expense is driven by the timing and valuation of new stock option grants. Stock based compensation expense in the third quarter of 2013 was $641 thousand compared to $270 thousand in the third quarter of 2012. Stock based compensation expense increased due to the grant of 3.5 million stock options in the nine month period September 30, 2013. 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, 2013	Three months ended September 30, 2012	Percent Change	Nine months ended September 30, 2013	Nine months ended September 30, 2012	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion and depreciation	14,369	5,952	141	37,573	11,067	240
Exploration and evaluation lease expiries	-	-	-	1,185	-	100
Accretion	89	45	98	245	100	145
	14,458	5,997	141	39,003	11,167	249
Percent of total revenue	28.7%	39.9%	(28)	32.6%	39.6%	(18)
Per boe ($)	27.67	30.65	(10)	28.84	29.99	(4)

Depletion, depreciation and accretion expense for the three month period ended September 30, 2013 was $14.5 million or $27.67 per boe compared to $6.0 million or $30.65 per boe in the comparable period in 2012. 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. The increase in depletion expense is a result of a 167 percent increase in production volumes and a significant increase to the capital base from an intensive drilling program including property and corporate acquisitions in 2012.

Accretion increased in the third quarter of 2013 to $89 thousand compared to $45 thousand in the comparable period in 2012. This is primarily due to increased costs attributable to drilling activities in 2012 and 2013. Accretion represents the time value of the asset retirement obligation and is calculated at the Company’s risk-free rate, currently 3.1 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, 2013, $1.2 million of costs associated with expired mineral leases were recognized as depletion expense in the statement of comprehensive earnings. There were no lease expires in the comparable period of 2012.

Gain on sale of assets

During the second quarter of 2012, the Company completed a minor undeveloped land disposition and asset exchange. The excess of the monetary and non-monetary consideration received over the carrying value of assets given up, resulted in the recognition of a net gain in the amount of $1.5 million.

Asset Retirement Obligations

As at September 30, 2013, the asset retirement obligation was $13.5 million. The liability increased by $941 thousand from the asset retirement obligation of $12.6 million as at December 31, 2012. This is related a downward revision to the estimate due to discounting the costs at a higher risk-free rate at September 30, 2013 relative to the rate applied at December 31, 2012 which was offset by significant asset retirement additions from drilling activities in the third quarter of 2013 and accretion expense.

Future and Current Income Taxes

The income tax provision for the period ended September 30, 2013 was $10.0 million for an effective tax provision rate of 27 percent. Deferred taxes of $8.3 million were recorded in the nine months ended September 30, 2013.

In the three and nine months ended September 30, 2013, the Company recorded a current tax expense of $750 thousand.

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, 2013, Raging River recorded funds from operations of $81.1 million and net earnings of $26.8 million. This is a significant increase from the 2012 results with funds from operations of $18.7 million and net earnings of $6.4 million, due primarily to increased production volumes, higher commodity pricing and lower cash costs per boe in 2013.

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,			Nine months ended September 30,		
	2013	2012	Percent Change	2013	2012	Percent Change
	($/boe)			*($/boe)*		
Petroleum and natural gas revenue	96.25	76.86	25	88.51	75.74	17
Realized gain(loss) on commodity contracts	(7.65)	0.04	n/a	(3.06)	0.96	(419)
Royalties	(8.86)	(7.70)	15	(7.85)	(7.70)	2
Net revenue	79.74	69.20	15	77.60	69.00	12
Operating expenses	(12.53)	(12.03)	4	(12.64)	(13.11)	(4)
Transportation expenses	(2.02)	(1.69)	20	(2.15)	(1.72)	25
Operating netback	65.19	55.48	17	62.81	54.17	16
General and administrative expenses	(1.85)	(2.48)	(25)	(1.89)	(3.15)	(40)
Financial charges	(0.32)	(0.51)	(37)	(0.41)	(0.77)	(47)
Funds from operations	63.02	52.49	20	60.51	50.25	20
Unrealized gain (loss) on financial instruments	(3.57)	(1.43)	150	(3.30)	0.73	(552)
Stock-based compensation expense	(1.23)	(1.38)	(11)	(1.16)	(1.04)	12
Gain on sale	-	-	-	-	3.94	(100)
Depletion, depreciation and accretion expense	(27.67)	(30.65)	(10)	(28.84)	(29.99)	(4)
Earnings before taxes	30.55	19.03	60	27.21	23.89	14
Current taxes	(1.44)	-	100	(0.55)	-	100
Future income tax provision	(6.65)	(4.86)	(37)	(6.84)	(6.38)	7
Net earnings	22.46	14.17	58	19.82	17.51	13

Capital Expenditures

Total exploration and development capital expenditures for the three and nine month period ended September 30, 2013 were $60.2 million and $108.4 million respectively, compared to $27.3 million and $58.9 million for the same periods in 2012. The expenditures are detailed below:

	Three months ended September 30, 2013	2012	Percent Change	Nine months ended September 30, 2013	2012	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Land	366	26	1,308	2,278	772	195
Property acquisitions	-	1,889	(100)	1,047	29,812	(96)
Geological and geophysical	69	328	(79)	209	620	(66)
Drilling and completions	58,569	24,536	139	101,578	27,041	276
Production facilities	1,178	470	151	3,256	638	410
Other	2	21	(90)	5	35	(86)
Exploration and development	60,184	27,270	121	108,373	58,918	84

In the third quarter of 2013, Raging River continued to remain active and drilled a total of 94 gross (71.1 net) horizontal Viking oil at a 100% success. During the third quarter of 2013, Raging River invested a total of $60.2 million including $58.6 million on drillings and completions.

In the first half of 2013, Raging River drilled a total of 50 (42.2 net) crude oil wells quarter including 49 horizontal Viking oil wells at a 100% success rate and one vertical stratigraphic test well.

During the second quarter, Raging River invested a total of $10.6 million including $8.4 million on drilling and completions in addition to $2.2 million on land and acquisitions.

During the first quarter of 2013, Raging River invested a total of $35.3 million in drilling and completion activities. Additionally the Company has expanded its undeveloped land base spending $746 thousand primarily in the core area of Dodsland in southwest Saskatchewan.

Drilling Activity

The following table summarizes our drilling results:

	Three months ended September 30, 2013 Gross	Net	2012 Gross	Net	Nine months ended September 30, 2013 Gross	Net	2012 Gross	Net
Natural gas	-	-	-	-	-	-	-	-
Crude oil	94	71.1	36	27.6	143	112.3	41	29.9
Test well	-	-	1	1	1	1	1	1
Service	-	-	-	-	-	-	-	-
Dry and abandoned	-	-	-	-	-	-	-	-
Total	94	71.1	37	28.6	144	113.3	42	30.9
Success	100%	100%	100%	100%	100%	100%	100%	100%

Liquidity and Capital Resources

At September 30, 2013, the Company had net debt of $42.4 million compared to net debt of $15.2 million at December 31, 2012. For the nine months ended September 30, 2013, funds from operations of $81.1 combined with capital expenditures of $108.4 million resulted in the ending net debt of $42.4 million. The Company expects to have adequate liquidity to fund the remainder of the 2013 capital expenditure budget of $270 million through a combination of funds flow from operations, the $125 million credit facility with the National Bank of Canada and the bought deal financing (see subsequent events).

Capital Resources

	September 30, 2013	2012
($ thousands)		
Capital Resources		
Bank debt available	125,000	65,000
Working capital deficiency	(42,446)	(25,768)
Total capital resources available	82,554	39,232

Common share information

CAPITALIZATION AND CAPITAL RESOURCES

Share Capital

	Three months ended September 30,		Nine months ended September 30,	
Outstanding common shares	2013	2012	2013	2012
Weighted average outstanding common shares (1)				
-Basic	156,757	122,382	156,757	115,212
-Diluted	169,485	123,437	167,186	115,854
Outstanding securities at September 30, 2013				
-Common shares				156,757,341
-Common share options – average strike price of $2.51				9,746,925
-Warrants issued through Private Placement – strike price of $2.00				14,375,000

(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 using the treasury stock method which assumes 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, 2013 was $851 million.

	September 30, 2013
Common shares outstanding	156,757,341
Share price (1)	$5.43
Total market capitalization	$851,192,362

(1) Represents the last price traded on the TSX Exchange ("TSX") on September 30, 2013.

As at November 14, 2013 the Company had 156,764,841 common shares outstanding.

	November 14, 2013
Outstanding securities at November 14, 2013	
-Common shares	156,764,841
-Stock options – weighted average strike price of $2.51	9,746,925
-Warrants issued through Private Placement – strike price of $2.00	14,367,500

Subsequent Events

Subsequent to the end of the quarter, the following event has occurred:

a) Financing

On November 12, 2013, the Company completed a bought deal financing for gross proceeds of $78.4 million and issued 14.0 million common shares at a price of $5.60 per common share.

b) Property Acquisition and Freehold Leasing Arrangement

As detailed in our press release of October 23, 2013, the Company entered into agreements to acquire Viking light oil assets consisting of 900 boe/d (85% light oil) of production and 40.3 net sections of highly prospective land targeting Viking oil for total consideration of approximately $105 million. The property acquisition is expected to close on November 21, 2013.

c) Credit Facility

The Company is negotiating a $225 million syndicated credit facility that is anticipated to close concurrent with the closing of the property acquisition.

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
Bank debt	6,096	-	-	-	6,096
Financial instruments	4,071	-	-	-	4,071
Operating lease obligations (note 1)	377	439	-	-	816
Total contractual obligations	10,544	439	-	-	10,983

1. Operating lease obligations consist of the office lease.

Off-Balance Sheet Arrangements

There are currently no significant off-balance sheet arrangements.

Related Party Transactions

Refer to description of the Company above for discussion of the common control transaction.

Summary of Quarterly Results

	Q3/13	Q2/13	Q1/13	Q4/12	Q3/12	Q2/12	Q1/12
Financial *(thousands of dollars except share data)*							
Petroleum and natural gas revenue	50,287	36,264	33,151	21,764	15,038	11,602	1,559
Funds flow from operations (1)	32,174	25,527	23,383	15,089	10,269	7,492	948
Per share - basic	0.21	0.16	0.15	0.12	0.08	0.07	0.01
- diluted	0.19	0.15	0.14	0.12	0.08	0.07	0.01
Net earnings	11,738	8,810	6,241	4,943	2,648	3,363	383
Per share - basic	0.07	0.06	0.04	0.04	0.02	0.03	-
- diluted	0.07	0.05	0.04	0.03	0.02	0.03	-
Capital expenditures, net	60,184	10,583	37,608	62,209	27,270	31,537	72
Capital expenditures – corporate acquisitions	-	-	-	5,211	-	-	-
Shareholders' equity	286,318	273,703	264,027	257,371	161,133	158,154	97,640
Weighted average shares *(thousands)*							
Basic	156,757	156,757	156,757	127,149	122,382	112,380	88,416
Diluted	169,485	166,546	164,775	129,380	123,437	112,380	97,640
Shares outstanding, end of period *(thousands)*							
Basic	156,757	156,757	156,757	156,757	122,382	122,382	91,041
Diluted	180,879	180,829	177,672	177,372	142,827	142,952	102,310
Operating *(6:1 boe conversion)*							
Average daily production							
Crude oil and NGLs *(bbls/d)*	5,495	4,387	4,454	3,027	2,073	1,667	1,345
Natural gas *(mcf/d)*	1,104	1,401	580	618	319	268	291
Barrels of oil equivalent (2) *(boe/d)*	5,679	4,620	4,550	3,130	2,127	1,711	1,394
Average selling prices(4)							
Crude oil and NGLs *($/bbl)*	98.98	89.71	82.29	77.54	78.54	76.28	76.95
Natural gas *($/mcf)*	2.43	3.55	3.18	3.05	1.91	1.37	1.38
Barrels of oil equivalent (2) *($/boe)*	96.25	86.26	80.95	75.59	76.86	74.50	74.56
Netbacks ($/boe)							
Operating							
Petroleum and natural gas revenue(4)	96.25	86.26	80.95	75.59	76.86	74.50	74.56
Realized gain on commodity contracts	(7.65)	(0.49)	0.15	0.83	0.04	2.25	-
Royalties	(8.86)	(7.46)	(6.94)	(6.69)	(7.70)	(7.79)	(7.10)
Operating expenses	(12.53)	(12.78)	(12.66)	(12.44)	(12.03)	(14.25)	(14.63)
Transportation expenses	(2.02)	(2.25)	(2.20)	(1.75)	(1.69)	(1.73)	(2.03)
Operating netback *($/boe)*	65.19	63.28	59.30	55.54	55.48	52.98	50.80
General and administrative expense	(1.85)	(1.95)	(1.88)	(2.30)	(2.48)	(3.97)	(3.25)
Financial charges	(0.32)	(0.61)	(0.32)	(0.79)	(0.51)	(0.90)	(2.21)
Corporate netback(3) *($/boe)*	63.02	60.72	57.10	52.41	52.49	48.10	45.34

(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) Corporate netbacks are calculated as the operating netback less general and administrative expenses, financial charges asset retirement obligations and transaction costs.
(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 later part of the first quarter of 2012, and continuing through 2012 and into 2013, 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 2013 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 2013.

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

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 interim 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. There have been no changes in the Company's internal controls over financial reporting during the period from July 1, 2013 to September 30, 2013 that have materially affected, or are reasonably likely to materially affect the Company's internal controls over financial reporting.

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 of 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 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

These interim financial statements have been prepared following the same accounting policies and methods of computation as the most recent annual consolidated financial statements as at and for the year ended December 31, 2012, except as noted below and except for income tax expense for the interim period which is based on an estimated average annual effective income tax rate. Significant accounting policies are described in note 3 of the December 31, 2012 annual consolidated financial statements.

The Company has adopted the following new and revised standards effective January 1, 2013:

IFRS 10 - Consolidated Financial Statements builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.

The Company assessed the consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS did not result in any change the consolidation status of any of its subsidiaries.

IFRS 11 - Joint Arrangements establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.

The Company has classified its joint arrangements and concluded that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements.

IFRS 13 - Fair Value Measurement defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.

The adoption of IFRS 13 did not require any changes to valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013.

IFRS 7 - These amendments to IFRS 7 introduce new disclosure requirements about the effects of offsetting financial assets and financial liabilities and related arrangements on an entity’s financial position. The disclosures will provide user with information that may be useful in evaluating the effect of any netting arrangements in an entity's financial position.

The adoption of IFRS 7 did not require any changes as the Company does not have significant offsetting arrangements.

Corporate Information

Board of Directors

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

GEORGE FINK [(1) (2) (3)]
Chairman & CEO, Bonterra Energy Corp.
Calgary, Alberta

RAYMOND P. MACK [(1) (2)]
Partner, Kenway Mack Slusarchuk Stewart LLP
Calgary, Alberta

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

DAVE PEARCE [(2) (3)]
Industry 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

DAVE BURTON, P. Eng.
Vice President Engineering

JASON JASKELA, P. Eng.
Vice President Production

GARY BUGEAUD (Corporate Secretary)
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