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") should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2013 and the audited consolidated financial statements for the year ended December 31, 2012 and the notes thereto. The interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Forward Looking Statements

This MD&A 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 factions more fully described from time to time in the reports and filings made by the Company with securities regulatory authorities. 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. 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 International Financial Reporting Standards ("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 March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012
Cash flow from operating activities	11,859	(2,140)
Changes in non – cash working capital	11,524	3,088
Funds flow from operations	23,383	948

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 currently 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 common of Crescent Point 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, 2013 and a closing date of March 15, 2013.

Accordingly the operations below for the comparative period reflect only a 15 day period in the period ended March 31, 2012.

Corporate Highlights

First quarter ended March 31, 2013

- Achieved record production of 4,550 boe/d (97% oil), an increase of 45% from the fourth quarter of 2012 volumes and an increase of 226% over the comparable period in 2012.
- Achieved a record corporate netback of $57.10/boe.
- Attained record corporate funds flow from operations of $23.4 million ($0.15/share basic). This is an increase of 55% from fourth quarter 2012 funds flow from operations of $15.1 million.
- The Company spent $37.6 million on development activities in the first quarter of 2013. A total of 45 (38.2 net) horizontal Viking oil wells were drilled with a 100% success rate.
- Increased our 2013 average production guidance to 4,750 boe/d and exit 2013 production guidance to 5,600 boe/d (95% oil).
- Raging River increased its credit facility to $125 million from $100 million. Maintained balance sheet strength with first quarter exit net debt of $29.4 million representing 0.3 times debt to the first quarter annualized cash flow.

Petroleum and Natural Gas Revenue

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change (%)
	(thousands of dollars)		
Liquids revenue	32,981	1,553	2,024
Natural gas revenue	166	6	2,667
Royalty revenue	4	-	100
	33,151	1,559	2,026
Operating: (6:1 boe conversion)			
Average daily production			
Liquids (bbls/d)	4,454	1,345	231
Natural gas (mcf/d)	580	291	99
Barrels of oil equivalent (boe/d)	4,550	1,394	226
Average Raging River sales price			
Liquids ($/bbl)	82.29	76.95	7
Natural gas ($/mcf)	3.18	1.38	130
Barrel of oil equivalent ($/boe)	80.95	74.56	9
Average Benchmark Prices			
Crude oil - WTI (US$/bbl)	94.30	102.84	(8)
Crude oil - Edmonton Par	88.65	92.81	(4)
Natural gas - AECO	3.08	2.58	19
Exchange rate (US$/Cdn$)	0.99	1.01	(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. Raging River's average quality adjustment to Edmonton Par pricing during the first quarter of 2013 was $6.36/bbl compared to $15.86/bbl in the first quarter of 2012. The Company's liquids price averaged $82.29/bbl for the first quarter of 2013 compared to $76.95/bbl in the first quarter of 2012. Raging River's realized natural gas price in the first quarter of 2013 was $3.18 per mcf compared to the AECO daily index average of $3.08 and $1.38 per mcf in the first quarter of 2012.

During the first quarter of 2013, the Company drilled a total of 45 gross (38.2 net) wells with a 100% success rate, all in Dodsland in southwest Saskatchewan.

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

The Company's production for the first quarter of 2013 increased to 4,550 boe/d from 1,394 boe/d in the first quarter of 2012, an increase of 226 percent. Quarter over quarter, production in the first quarter of 2013 increased to 4,550 boe/d from 3,130 boe/d in the fourth quarter of 2012, an increase of 45 percent. The year over year increase was attributable to a successful drilling program in 2012 and 2013 combined with the 2012 corporate and property acquisitions.

Petroleum and natural gas revenue in the three month period March 31, 2013 was $33.2 million as compared to $1.6 million in the comparable period of 2012. This increase was the result of a 226 percent increase in production volumes.

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 May 9, 2013 the Company has the following price contracts in place by quarter:

2013

Q2

Crude oil	Fixed	Apr 2013 – Jun 2013	1,800 bbls/d	Cdn $95.89/bbl	WTI
Crude oil	Collar	Apr 2013 – Jun 2013	200 bbls/d	Cdn $95.00 -$104.25	WTI
Crude oil	Differential	Apr 2013 – Jun 2013	733 bbls/d	Cdn$5.63	WTI
Natural Gas	Fixed	Apr 2013 – Jun 2013	500 GJs/d	Cdn $3.28/GJ	AECO

Q3

Crude oil	Fixed	Jul 2013 – Sept 2013	2,000 bbls/d	Cdn $95.20	WTI
Crude oil	Collar	Jul 2013 – Sept 2013	200 bbls/d	Cdn $95.00 -$104.25	WTI
Crude oil	Collar	Jul 2013 – Sept 2013	200 bbls/d	Cdn $90.00 -$102.00	WTI
Natural Gas	Fixed	Jul 2013 – Sept 2013	500 GJs/d	Cdn $3.28/GJ	AECO

Q4

Crude oil	Fixed	Oct 2013 – Dec 2013	2,000 bbls/d	Cdn $95.20	WTI
Crude oil	Collar	Oct 2013 – Dec 2013	200 bbls/d	Cdn $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	400 bbls/d	Cdn $94.20	WTI

Realized & unrealized gain on financial instruments

For the three months ended March 31, 2013, the Company realized gains of $61 thousand. The realized gain represents the commodity contracts settled during the three months ended March 31, 2013.

As of March 31, 2013, the fair value of Raging River's outstanding commodity contracts is an unrealized liability of $1.2 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 March 31, 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 March 31, 2013. The unrealized loss of $1.6 million represents the fair value change of the underlying commodity contracts to be settled in the future.

Royalties

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	(thousands of dollars)		
Crown	944	74	1,176
Saskatchewan resource surcharge	665	26	2,454
Freehold and GORR	1,235	48	2,473
	2,844	148	1,821
Percent of total revenue	8.6%	9.5%	(9)
Per boe ($)	6.94	7.10	(2)

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and the Saskatchewan resource surcharge. Royalties increased to $2.8 million in the first quarter of 2013 from $148 thousand in the first quarter of 2012, due to a 226 percent increase in sales volumes. The Company's average royalty rate was 8.6% in the first quarter compared to 9.5% in the comparable quarter of 2012. Royalties as a percentage of revenue decreased in first quarter of 2013 compared to the fourth quarter of 2012 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 through 2013 to approximately 9.5% as a larger percentage of wells having freehold royalties will be drilled in the remainder of 2013.

Operating Expenses

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	(thousands of dollars)		
Total operating costs ($000's)	5,183	306	1,594
Percent of total revenue	15.6%	19.6%	(20)
Per boe ($)	12.66	14.63	(13)

Operating expenses increased to $5.2 million in the first quarter of 2013 from $306 thousand in the first quarter of 2012. The increase is attributable to the 226 percent increase in production volumes. Efficiencies in operations combined with economies of scale as a result of increased production volumes, led to the 13 percent decline in per unit operating costs to $12.66/boe in 2013. Quarter over quarter per unit operating expenses increased by $0.22/boe as a direct result of higher operating costs associated with winter operations.

The Company is targeting operating costs for 2013 to be approximately $12.50/boe.

Transportation Expenses

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	(thousands of dollars)		
Total transportation costs ($000's)	903	42	2,049
Percent of total revenue	2.7%	2.7%	-
Per boe ($)	2.20	2.03	9

Transportation costs increased to $903 thousand in the first quarter from $42 thousand in the first quarter of 2012 as a result of increased production volumes. Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. On a per boe basis, transportation expenses for the quarter ended March 31, 2013 increased by $0.45 per boe from the fourth quarter of 2012. The increase is due to the challenging weather conditions during the first quarter of 2013 in southwest Saskatchewan which required additional costs for clean oil trucking.

Transportation costs are expected to be up to $0.50/boe higher for the second quarter than the first quarter due to spring break up conditions. For the second half of 2013 we expect to return to transportation costs of approximately $2.00 per boe.

General and Administrative Expenses

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	(thousands of dollars)		
General and administrative	1,237	86	1,338
Overhead recoveries	(222)	-	(100)
Capitalized G & A	(245)	(18)	1,261
	770	68	
Percent of total revenue	2.3%	5.5%	(58)
Per boe ($)	1.88	3.25	(42)

Net general and administration expenses for the first quarter ended March 31, 2013 were $770 thousand or $1.88/boe compared to $68 thousand or $3.25/boe in the first quarter of 2012. General and administrative expenses increased in the first quarter as a result of employee related costs driven by the capital growth of Raging River and its operations. Capitalized G&A and overhead recoveries also increased in the first quarter due to a substantial increase in capital spending. Costs on a boe basis decreased by 42% from the first quarter of 2012 primarily as a result of a 226 percent increase in production. Additionally costs on a boe basis decreased from the prior quarter as a result of a 45% increase in production.

Financial Charges

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	(thousands of dollars)		
Financial charges	129	47	175
Percent of total revenue	0.4%	3.0%	(87)
Per boe ($)	0.32	2.21	(86)

Financial charges for the first quarter ended March 31, 2013 were $129 thousand or $0.32/boe compared to $47 thousand or $2.21/boe in the first quarter of 2012. Interest on bank debt increased in the first quarter due to carrying higher average debt levels than in the first quarter in 2012. As at March 31, 2013 the Company had drawn $12.3 million against the available credit facility of $125 million.

Stock-based Compensation

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
Stock based compensation	295	-	100
Percent of total revenue	0.9%	-	100
Per boe ($)	0.72	-	100

As at March 31, 2013 the Company has issued a total of 6.5 million stock options with a weighted average fair value of $0.43 per option. The expense is driven by the timing and valuation of new stock option grants. Stock based compensation expense in the first quarter of 2013 was $295 thousand. 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 March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	(thousands of dollars)		
Depletion and depreciation	11,581	613	1,789
Exploration and evaluation lease expiries	1,185	-	
Accretion	73	8	813
	12,839	621	1,967
Percent of total revenue	38.7%	39.8%	(3)
Per boe ($) – Depletion and depreciation	28.46	29.70	(4)
Per boe ($) – Exploration and evaluation lease expiries	2.89	-	100

Depletion and depreciation expense for the three month period ended March 31, 2013 was $11.6 million or $28.46/boe compared to $613 thousand or $29.70/boe in the first quarter of 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 226% increase in production volumes, combined with a large increase to the capital base from capital expenditures including property and corporate acquisitions in 2012.

Accretion increased in 2013 to $73 thousand primarily due to increased costs attributable to drilling activities in the first quarter. Accretion represents the time value of the asset retirement obligation and is calculated at the Company’s risk-free rate, currently 2.49 percent. It will continue to increase with the passage of time and the increases in asset retirement obligations.

During the three month period ended March 31, 2013, $1.2 million of costs associated with expired mineral leases were recognized as depletion expense in the consolidated statement of comprehensive earnings. There were no lease expires in the comparable period of 2012.

Asset Retirement Obligations

As at March 31, 2013, the asset retirement obligation was $13.4 million. The Company recorded an increase of $806 thousand in the obligation from the asset retirement obligation of $12.6 million as at December 31, 2012. This is related to its first quarter 2013 capital exploration and development program which were offset by a downward revision to the estimate due to discounting the costs at a higher risk-free rate at March 31, 2013 relative to the rate applied at December 31, 2012.

Future Income Taxes

A future income tax provision for the period ended March 31, 2013 was $2.4 million for an effective tax provision rate of 27.7 percent.

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 three month period of operations ended March 31, 2013, Raging River recorded funds from operations of $23.4 million and net earnings of $6.2 million. This is a significant increase from the 2012 results with funds from operations of $948 thousand and net earnings of $383 thousand, due primarily to both increased production volumes, lower cash costs and lower depletion rates 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 March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	($/boe)		
Petroleum and natural gas revenue	80.95	74.56	9
Realized gain on commodity contracts	0.15	-	100
Royalties	(6.94)	(7.10)	(2)
Net revenue	74.16	67.46	10
Operating expenses	(12.66)	(14.63)	(13)
Transportation expenses	(2.20)	(2.03)	9
Operating netback	59.30	50.80	17
Financial charges	(0.32)	(2.21)	(86)
General and administrative expenses	(1.88)	(3.25)	(42)
Funds from operations	57.10	45.34	26
Unrealized gain (loss) on financial instruments	(3.94)	7.85	(150)
Exploration and evaluation lease expiries	(2.89)	-	100
Stock based compensation	(0.72)	-	100
Depletion, depreciation and accretion expense	(28.46)	(29.70)	(4)
Net earnings before taxes	21.09	23.49	(10)
Future income tax provision	(5.85)	(5.17)	13
Net earnings	15.24	18.32	(17)

Capital Expenditures

Total exploration and development capital expenditures for the first quarter March 31, 2013 were $37.6 million. The expenditures are detailed below:

	Three months ended March 31, 2013	Commencement of operations March 16, 2012 to March 31, 2012	Percent Change
	(thousands of dollars)		
Land	746	49	N/A
Geological and geophysical	54	5	N/A
Drilling and completions	35,289	18	N/A
Production facilities	1,518	-	N/A
Other	1	-	N/A
Exploration and development	37,608	72	N/A

In the three months ended March 31, 2013, Raging River drilled a total of 45 (38.2 net) crude oil wells with a 100 percent success rate. 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 March 31, 2013		Commencement of operations March 16, 2012 to March 31, 2012	
	Gross	Net	Gross	Net
Natural gas	-	-	-	-
Crude oil	45	38.2	-	-
Service	-	-	-	-
Dry and abandoned	-	-	-	-
Total	45	38.2	-	-
Success	100%	100%	-	-

Liquidity and Capital Resources

At March 31, 2013, the Company had net debt of $29.4 million compared to net debt of $15.2 million at December 31, 2012. For the three months ended March 31, 2012, funds from operations of $23.4 combined with capital expenditures of $37.6 million resulted in the ending net debt of $29.4 million. The Company expects to have adequate liquidity to fund the 2013 capital expenditure budget of $125 million through a combination of funds flow from operations, and the $125 million credit facility with the National Bank of Canada.

Capital Resources

	March 31, 2013	2012
($ thousands)		
Capital Resources		
Bank debt available	125,000	45,000
Working capital deficiency	(29,381)	(35,123)
Total capital resources available	95,619	9,877

Common share information

CAPITALIZATION AND CAPITAL RESOURCES

Share Capital

	March 31,	
Outstanding common shares	2013	2012
Weighted average outstanding common shares (1)		
-Basic	156,757,341	88,415,708
-Diluted	164,775,352	94,342,062
Outstanding Securities at March 31, 2013		
-Common shares	156,757,341	91,041,041
-Stock options – weighted average strike price of $1.98	6,540,000	-
-Purchase warrants issued through Plan of Arrangement	-	11,268,750
-Warrants issued through Private Placement	14,375,000	14,375,000

(1) Per share information is calculated on the basis of the weighted average number of common shares outstanding during the fiscal period. Diluted per 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 per 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 March 28, 2013 was $613 million.

	March 31, 2013
Common shares outstanding	156,757,341
Share price (1)	$3.91
Total market capitalization	$612,921,*203*

(1) Represents the last price traded on the TSX Venture Exchange ("TSXV") on March 31, 2013.

As at May 9, 2013 the Company had 156,757,341common shares outstanding.

	May 9, 2013
Outstanding securities at May 9, 2013	
-Common shares	156,757,341
-Stock options – weighted average strike price of $2.49	9,681,925
-Warrants issued through Private Placement	14,375,000

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	12,348	-	-	-	12,348
Operating lease obligations (note 1)	377	628	-	-	1,005
Total contractual obligations	12,725	628	-	-	13,353

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

	Q1/13	Q4/12	Q3/12	Q2/12	Commencement of operations March 16, 2012 to March 31, 2012
Financial *(thousands of dollars except share data)*					
Petroleum and natural gas revenue	33,151	21,764	15,038	11,602	1,559
Funds flow from operations [1]	23,383	15,089	10,269	7,492	948
Per share - basic	0.15	0.12	0.08	0.07	0.01
- diluted	0.14	0.12	0.08	0.07	0.01
Net earnings	6,241	4,943	2,648	3,363	383
Per share - basic	0.04	0.04	0.02	0.03	-
- diluted	0.04	0.03	0.02	0.03	-
Capital expenditures, net	37,608	62,209	27,270	31,537	72
Capital expenditures – corporate acquisitions	-	5,211	-	-	-
Shareholders' equity	264,027	257,371	161,133	158,154	97,640
Weighted average shares *(thousands)*					
Basic	156,757	127,149	122,382	112,380	88,416
Diluted	164,775	129,380	123,437	112,380	97,640
Shares outstanding, end of period *(thousands)*					
Basic	156,757	156,757	122,382	122,382	91,041
Diluted	177,672	177,372	142,827	142,952	102,310
Operating *(6:1 boe conversion)*					
Average daily production					
Crude oil and NGLs *(bbls/d)*	4,454	3,027	2,073	1,667	1,345
Natural gas *(mcf/d)*	580	618	319	268	291
Barrels of oil equivalent [2] *(boe/d)*	4,550	3,130	2,127	1,711	1,394
Average selling prices[4]					

Crude oil and NGLs *($/bbl)*	82.29	77.54	78.54	76.28	76.95
Natural gas *($/mcf)*	3.18	3.05	1.91	1.37	1.38
Barrels of oil equivalent (2) *($/boe)*	80.95	75.59	76.86	74.50	74.56
Netbacks ($/boe)					
Operating					
Petroleum and natural gas revenue(4)	80.95	75.59	76.86	74.50	74.56
Realized gain on commodity contracts	0.15	0.83	0.04	2.25	-
Royalties	(6.94)	(6.69)	(7.70)	(7.79)	(7.10)
Operating expenses	(12.66)	(12.44)	(12.03)	(14.25)	(14.63)
Transportation expenses	(2.20)	(1.75)	(1.69)	(1.73)	(2.03)
Operating netback *($/boe)*	59.30	55.54	55.48	52.98	50.80
General and administrative expense	(1.88)	(2.30)	(2.48)	(3.97)	(3.25)
Financial charges	(0.32)	(0.79)	(0.51)	(0.90)	(2.21)
Corporate netback(3) *($/boe)*	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 the 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 first 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

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 Consolidated 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 consolidated 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 amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013.

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)
Burnet, Duckworth & Palmer LLP

Head Office
Suite 710, 400 – 5th Avenue SW
Calgary, Alberta T2P 0L6
Tel: (403) 387-2950
Fax: (403) 387-2951

Bankers
National Bank of Canada
Calgary, Alberta

Auditors
KPMG LLP
Calgary, Alberta

Independent Reservoir Consultants
Sproule Associates Limited
Calgary, Alberta

Website: www.rrexploration.com