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 August 11, 2015 and should be read in conjunction with the unaudited interim financial statements for the three and six months ended June 30, 2015 and the audited financial statements for the year ended December 31, 2014 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, details of the 2015 capital budget including expected capital expenditures, expectations that the company will have adequate liquidity to fund operations and capital expenditures. 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. The forward-looking statements contained herein are based on certain key expectations and assumptions made by the Company, including but not limited to expectations and assumptions concerning including but not limited to expectations and assumptions with respect to the success of optimization and efficiency improvement projects, the availability of capital, current legislation, pipeline capacity, receipt of required regulatory approval, the success of future drilling and development activities, the performance of existing wells, the performance of new wells, Raging River's growth strategy, general economic conditions, availability of required equipment and services and the costs of obtaining such equipment and services, and prevailing commodity prices. 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, 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 June 30,		Six months ended, June 30,	
	2015	2014	2015	2014
	(thousands of dollars)			
Cash flow from operating activities	42,210	66,309	50,773	95,185
Changes in non – cash working capital	7,325	(10,026)	32,241	10,910
Funds flow from operations	49,535	56,283	83,014	106,095

The Company presents funds flow 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, operating netbacks and funds flow 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, secondly, the amount of revenues received on a per unit of production basis after the royalties, operating and transportation costs and thirdly, the amount of revenues received on a per unit of production basis after the royalties, operating and transportation costs, general and administrative expenses, financial charges, asset retirement expenditures and current taxes. Net debt represents current assets less current liabilities and bank debt and 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, such measures 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. 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.

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

Second quarter ended June 30, 2015

- Achieved another quarterly production record with average production of 13,347 boe/d (97% oil) representing an increase of 34% over the comparable period in 2014 and a 21% production per share increase from the comparable period of 2014.

- The Company's capital expenditures were $33.4 million including $32.3 million on development activities in addition to $1.1 million on land. A total of 36 net Viking horizontal wells were drilled and a total of 48 net wells were completed and placed on stream inclusive of the 19.4 net wells drilled and not completed in the first quarter. Average on stream costs during the quarter were $700,000 per well representing a 22% cost reduction from the average costs seen in 2014.

- Generated top decile operating netbacks of $42.92/boe and funds flow netbacks of $40.79/boe in addition to positive earnings of $10.00/boe.

- Achieved our eighth consecutive quarterly decrease in operating and transportation costs to $12.08/boe, a 14% reduction from the comparable quarter of 2014 and a 5% reduction quarter over quarter.

- Continued our diligent cost control with top decile general and administrative costs of $1.30/boe, a reduction of 9% from the comparable period in 2014.

- Maintained balance sheet strength with second quarter exit net debt of $99.1 million representing 0.5 times debt to the second quarter annualized cash flow.

Petroleum and Natural Gas Revenue

	Three months ended June 30, 2015	2014	Percent Change	Six months ended June 30, 2015	2014	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Liquids revenue	72,653	87,617	(17)	126,982	167,063	(24)
Natural gas revenue	696	1,108	(37)	1,345	2,271	(41)
Royalty revenue	116	206	(44)	144	304	(53)
	73,465	88,931	(17)	128,471	169,638	(24)
Operating: (6:1 boe conversion)						
Average daily production						
Liquids (bbls/d)	12,856	9,500	35	12,863	9,463	36
Natural gas (mcf/d)	2,947	2,765	7	2,795	2,518	11
Barrels of oil equivalent (boe/d)	13,347	9,960	34	13,329	9,883	35
Average Raging River sales price						
Liquids ($/bbl)	62.20	101.59	(39)	54.60	97.71	(44)
Natural gas ($/mcf)	2.59	4.41	(41)	2.66	4.98	(47)
Barrel of oil equivalent ($/boe)	60.49	98.11	(38)	53.25	94.83	(44)
Average Benchmark Prices						
Crude Oil - WTI (US$/bbl)	57.94	102.96	(44)	53.29	100.82	(47)
Crude Oil - MSW	67.64	105.55	(36)	59.71	102.67	(42)
Natural gas - AECO	2.67	4.71	(43)	2.71	5.17	(48)
Exchange rate (US$/Cdn$)	0.81	0.92	(12)	0.81	0.91	(11)

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 Mixed Sweet Blend (MSW). The continued significant decline in the WTI price was only partially offset by a weakened Canadian dollar which has resulted in a lower realized price for the Company in both the three and six month periods ended June 30, 2015. Raging River’s average quality adjustment to MSW pricing during the second quarter of 2015 was $5.44/bbl compared to $3.96/bbl in the second quarter of 2014. The Company's liquids price averaged $62.20/bbl for the second quarter of 2015, down 39% from $101.59/bbl in the second quarter of 2014.

Similarly, Raging River’s average quality adjustment to MSW pricing increased in the first half of 2015 to $5.11/bbl from $4.96/bbl in the first half of 2014. The Company’s liquids price averaged $54.60/bbl in the first half of 2015, down 44% from the average price of $97.71/bbl received in the second half of 2014.

The AECO natural gas price declined in the three and six months period June 30, 2015 from the comparable periods in 2014 due to above average input into storage from an oversupplied market, resulting in downward pressure on natural gas pricing and a decrease in the natural gas price realized by the Company. Raging River’s realized natural gas price in the three and six month periods ended June 30, 2015, was $2.67 per mcf and $2.71 per mcf respectively, compared to $4.71 per mcf and $5.17 per mcf for the same periods in 2014.

During the first half of 2015, the Company drilled a total of 96 gross (89.3 net) wells with a 100% success rate, primarily in Dodsland in southwest Saskatchewan.

Production	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13	Q2/13
Liquids (bbls/d)	12,856	12,870	12,059	10,278	9,500	9,427	7,458	5,495	4,387
Natural gas (mcf/d)	2,947	2,641	2,931	2,406	2,765	2,269	1,912	1,104	1,401
Total (boe/d)	13,347	13,310	12,548	10,679	9,960	9,805	7,777	5,679	4,620
% increase over prior quarter	-	6%	18%	7%	2%	26%	37%	23%	2%
Production per 1 million shares	67.4	70.0	69.6	59.3	55.5	55.9	47.4	36.2	29.5
Per share % increase (decrease) over prior quarter	(4%)	1%	17%	7%	(1%)	18%	31%	23%	2%

The Company's production for the second quarter of 2015 increased to 13,347 boe/d from 9,960 boe/d in the second quarter of 2014, an increase of 34%. Quarter over quarter, production in the second quarter of 2015 at 13,347 boe/d remained consistent with production of 13,310 boe/d in the first quarter of 2015. The year over year increase of 34% was primarily attributable to a successful drilling program in 2014 and 2015.

Petroleum and natural gas revenue in the three month period June 30, 2015 was $73.5 million as compared to $88.9 million in the comparable period of 2014. This decrease was attributable to a 38% decrease in commodity pricing that was partially offset by a 34% increase in production volumes.

Petroleum and natural gas revenues in the six month period June 30, 2015 were $128.5 million, as compared to $169.6 million in the comparable period of 2014, representing a decrease of $41.1 million or 24%. This decrease in revenue is again attributed to a 44% decline in commodity prices that was partially offset by a 35% 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 August 11, 2015 the Company has the following price contracts in place by quarter:

2015

Q3

Crude oil	Fixed	Jul 2015 – Sept 2015	750 bbls/d	Cdn $73.40/bbl	WTI
Crude oil	Differential	Jul 2015 – Sept 2015	1,000 bbls/d	Cdn $3.30/bbl	WTI/Edm blend
Natural gas	Fixed	Jul 2015 – Sept 2015	1,000 GJs/d	Cdn $2.92/GJ	AECO

Q4

Crude oil	Fixed	Oct 2015 – Dec 2015	750 bbls/d	Cdn $75.33/bbl	WTI
Natural gas	Fixed	Oct 2015 – Dec 2015	1,000 GJs/d	Cdn $2.92/GJ	AECO

Realized & unrealized gain/loss on financial instruments

The realized gain/loss represents the commodity contracts settled during the three and six months ended June 30, 2015. As the oil commodity contracts are referenced to 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 significant decline in the WTI in the first half of 2015 was only partially offset by the weak Canadian dollar which resulted in realized gains for the three and six months period ended June 30, 2015. For the three month period ended June 30, 2015, the Company realized gains of $446 thousand (three months ended June 30, 2014: realized losses of $2.1 million) and for the six month period ended June 30, 2015, the Company recorded a $2.3 million gain (six months ended June 30, 2014: realized losses of $3.8 million).

As of June 30, 2015, the fair value of Raging River's outstanding commodity contracts is an unrealized liability of $123 thousand 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 June 30, 2015, 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 June 30, 2015. The unrealized loss of $2.6 million for the six month period ended June 30, 2015, represents the fair value change of the underlying commodity contracts to be settled in the future. In comparison, an unrealized loss of $743 thousand was recorded for the six months ended June 30, 2014.

In the second quarter of 2015, the Company had unrealized losses of $1.6 million compared to unrealized gains of $831 thousand in the second quarter of 2014.

Royalties

	Three months ended June 30,		Percent	Six months ended June 30,		Percent
	2015	2014	Change	2015	2014	Change
	(thousands of dollars)			*(thousands of dollars)*		
Crown	1,370	2,114	(35)	2,586	4,298	(40)
Saskatchewan resource surcharge	1,303	1,632	(20)	2,343	3,211	(27)
Freehold and GORR	4,443	4,979	(11)	7,977	8,516	(6)
	7,116	8,725	(18)	12,906	16,025	(19)
Percent of total revenue	9.7%	9.8%	(1)	10.0%	9.4%	6
Per boe ($)	5.86	9.63	(39)	5.35	8.96	(40)

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and Saskatchewan resource surcharge. Royalties decreased to $7.1 million in the second quarter of 2015 from $8.7 million in the second quarter of 2014 primarily due to a 38% decline in commodity pricing. In the second quarter of 2015, the royalty rate of 9.7% was consistent with the royalty rate in the comparable period at 9.8%.

During the six months ended June 30, 2015, royalties decreased 19% to $12.9 million from $16.0 million in the comparable period. The decrease is again primarily a result of a 44% decrease in commodity pricing. The Company's average royalty rate was 10.0% in the first half of 2015 compared to 9.4% in the comparable quarter of 2014 due to a larger percentage of wells having freehold royalties drilled throughout the second half of 2014 and in the first half of 2015.

Operating Expenses

	Three months ended June 30,		Percent	Six months ended June 30,		Percent
	2015	2014	Change	2015	2014	Change
Total operating costs ($000's)	12,984	10,869	19	26,590	21,903	21
Percent of total revenue	17.7%	12.2%	45	20.7%	12.9%	60
Per boe ($)	10.69	11.99	(11)	11.02	12.24	(10)

Operating expenses increased to $13.0 million in the second quarter of 2015 from $10.9 million in the second quarter of 2014. The increase is attributable to the 34% increase in production volumes. During the six months ended June 30, 2015, operating expenses increased 21% to $26.6 million from $21.9 million in the comparable period. The increase is primarily a result of a 35% increase in production volumes.

Operating costs averaged $10.69/boe in the second quarter of 2015 and $11.02/boe in the year to date. This represents a decrease of 11% or $1.30/boe from $11.99/boe in the second quarter of 2014 and a decrease of 10% or $1.22/boe from $12.24/boe in the first half of 2014. Operating costs per boe decreased in both the three and six month periods ended June 30, 2015, due to a combination of a component of operating costs being fixed with increased production, improved operating efficiencies and mild spring-break-up conditions.

Transportation Expenses

	Three months ended June 30, 2015	Three months ended June 30, 2014	% Change	Six months ended June 30, 2015	Six months ended June 30, 2014	% Change
Total transportation costs ($000's)	1,688	1,804	(6)	3,305	3,574	(8)
% of total revenue	2.3%	2.0%	15	2.6%	2.1%	24
Per boe ($)	1.39	1.99	(30)	1.37	2.00	(32)

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs decreased to $1.7 million in the second quarter of 2015 from $1.8 million in the second quarter of 2014. During the six month ended period June 30, 2015, transportation costs decreased 8% to $3.3 million from $3.6 million in the comparable period. The decrease in transportation costs is primarily due to more volumes being pipeline connected from infrastructure built in 2014, thereby reducing higher clean oil trucking.

Transportation costs averaged $1.39/boe in the second quarter of 2015 and $1.37/boe in the year to date. This represents a decrease of 30% from $1.99/boe in the second quarter of 2014 and a decrease of 32% from $2.00/boe in the first half of 2014. Transportation costs per boe decreased in both the three and six month periods ended June 30, 2015, due to a larger portion of our clean oil being transported by pipeline, which has a lower cost per boe, cost optimization in trucking charges and mild spring-break-up conditions.

General and Administrative ("G&A") Expenses

	Three months ended June 30, 2015	Three months ended June 30, 2014	% Change	Six months ended June 30, 2015	Six months ended June 30, 2014	% Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	2,302	2,056	12	4,709	4,053	16
Overhead recoveries	(136)	(157)	(13)	(311)	(422)	(26)
Capitalized G&A	(589)	(601)	(2)	(1,181)	(1,040)	14
	1,577	1,298	21	3,217	2,591	24
% of total revenue	2.1%	1.5%	40	2.5%	1.5%	67
Per boe ($)	1.30	1.43	(9)	1.33	1.45	(8)

The Company incurred gross G&A expenses of $2.3 million and $4.7 million, respectively, during the three and six month periods ended June 30, 2015. Increased general and administrative costs before recoveries and capitalization were mainly the result of increased costs including office rent and head office staff to accommodate the Company's capital expenditure program and the larger operations resulting from significant increases in production. Higher salary costs were driven by increased personnel including technical and operations staff.

Net G&A expenses incurred were $1.6 million or $1.30 per boe and $3.2 million or $1.33 per boe, respectively, during the three and six month periods ended June 30, 2015. The decrease in net G&A per boe from the comparable periods is a result of efficiencies achieved with the higher production levels.

Financial Charges

	Three months ended June 30,		%	Six months ended June 30,		%
	2015	2014	Change	2015	2014	Change
Financial charges ($000's)	1,011	1,078	(6)	1,765	1,985	(11)
% of total revenue	1.4%	1.2%	17	1.4%	1.2%	17
Per boe ($)	0.83	1.19	(30)	0.73	1.11	(34)

Financial charges during the three and six month periods ended June 30, 2015, were $1.0 million and $1.8 million respectively compared to $1.1 million and $2.0 million respectively for 2014. Interest on bank debt decreased in both the three and six month periods ended June 30, 2015, due to carrying slightly lower average debt levels throughout the first half of 2015 as compared to 2014. In the first quarter of 2015, the Company completed a bought deal financing issuing 13.8 million common shares at $6.40 per common share for net proceeds of $83.8 million which allowed the Company to reduce debt and free up borrowing capacity, which was redrawn to fund the 2015 capital expenditure program. As at June 30, 2015 the Company had drawn $54.5 million against the available credit facility of $300 million.

Stock-based Compensation

	Three months ended June 30,		%	Six months ended June 30,		%
	2015	2014	Change	2015	2014	Change
Stock based compensation ($000's)	1,310	1,170	12	2,692	1,861	45
% of total revenue	1.8%	1.3%	38	2.1%	1.1%	91
Per boe ($)	1.08	1.29	(16)	1.12	1.04	8

As at June 30, 2015, the Company has issued a total of 12.7 million stock options with a weighted average fair value of $1.47 per option. Stock based compensation expense during the three and six month periods ended June 30, 2015, were $1.3 million and $2.7 million respectively compared to $1.2 million and $1.9 million respectively for 2014. Stock based compensation expense increased in the second quarter and first half of 2015, due to 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 June 30, 2015	Three months ended June 30, 2014	% Change	Six months ended June 30, 2015	Six months ended June 30, 2014	% Change
	(thousands of dollars)			*(thousands of dollars)*		
Exploration and evaluation lease expiries	-	-	-	2,512	581	332
Depletion and depreciation	27,609	21,038	31	54,876	41,388	33
Accretion	260	168	55	508	325	56
	27,869	21,206	31	57,896	42,294	37
% of total revenue	37.9%	23.8%	59	45.1%	24.9%	81
Per boe ($) – Depletion and depreciation	22.95	23.40	(2)	22.96	23.32	(2)
Per boe ($) – Exploration and evaluation lease expiries	-	-	-	1.04	0.32	225

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 $27.9 million and $55.4 million respectively for the three and six month periods ended June 30, 2015. The increase in depletion expense is a result of an increase in production volumes, combined with a large increase to the capital base from capital expenditures from an intensive drilling program. The per boe depletion and depreciation rate remained consistent for both the three and six month periods ended June 30, 2015, as capital additions were offset by reserve additions.

Accretion increased in the second quarter of 2015 to $260 thousand from $168 thousand in the comparable quarter of 2014. 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 2.3%. It will continue to increase with the passage of time and the increases in asset retirement obligations.

During the six month period ended June 30, 2015, $2.5 million of costs associated with expired mineral leases were recognized as exploration and evaluation expense in the statement of comprehensive earnings. In comparison, $581 thousand of lease expiries were recorded in the first half of 2014. Saskatchewan crown land leases come up for renewal annually in the first quarter of the year.

Asset Retirement Obligations

As at June 30, 2015, the asset retirement obligation of the Company was $49.6 million. The Company recorded an increase of $7.1 million in the obligation from the asset retirement obligation of $42.5 million as at December 31, 2014. This is related to the capital exploration and development program for the first half of 2015, and an upward revision to the estimate due the revaluation of asset retirement obligations acquired in the property acquisition. Asset retirement obligations acquired as part of an acquisition are initially measured at fair value using a credit-adjusted risk-free rate. The revaluation using a risk-free rate at the end of the period resulted in an increase of $2.0 million (revision to estimate at December 31, 2014 - $10.6 million).

Income Taxes

The Company recorded a deferred income tax provision of $6.6 million and $6.9 million respectively for the three and six month periods ended June 30, 2015, for an effective tax rate of 35%. In the second quarter of 2015, the proposed corporate tax rate increase in Alberta from 10% to 12% was substantially enacted. As a result of this change, a $1.7 million provision was recorded in deferred income tax expense during the period which resulted in the increased tax rate.

Raging River does not have a current income taxes payable as at June 30, 2015 due to the decline in commodity pricing.

Funds Flow from Operations and Net Earnings

The Company's funds flow 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 six month period of operations ended June 30, 2015, Raging River recorded funds flow from operations of $83.0 million and net earnings of $12.9 million. This decrease from the 2014 results with funds flow from operations of $106.1 million and net earnings of $54.6 million is due primarily to the significant decline in commodity pricing which was partially offset by increased production volumes and lower cash costs per boe.

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

	Three months ended June 30, 2015	Three months ended June 30, 2014	% Change	Six months ended June 30, 2015	Six months ended June 30, 2014	% Change
	($/boe)			*($/boe)*		
Petroleum and natural gas revenue	60.49	98.11	(38)	53.25	94.83	(44)
Realized gain (loss) on commodity contracts	0.37	(2.34)	(116)	0.97	(2.10)	(146)
Royalties	(5.86)	(9.63)	(39)	(5.35)	(8.96)	(40)
Net revenue	55.00	86.14	(36)	48.87	83.77	(42)
Operating expenses	(10.69)	(11.99)	(11)	(11.02)	(12.24)	(10)
Transportation expenses	(1.39)	(1.99)	(30)	(1.37)	(2.00)	(32)
Operating netback	42.92	72.16	(41)	36.48	69.53	(48)
General and administrative expenses	(1.30)	(1.43)	(9)	(1.33)	(1.45)	(8)
Financial charges	(0.83)	(1.19)	(30)	(0.73)	(1.11)	(34)
Asset retirement expenditures	-	-	-	(0.01)	-	100
Current taxes	-	(7.45)	(100)	-	(7.66)	(100)
Funds flow from operations	40.79	62.09	(34)	34.41	59.31	(42)
Unrealized gain (loss) on financial instruments	(1.33)	0.92	(245)	(1.10)	(0.42)	162
Stock-based compensation expense	(1.08)	(1.29)	(16)	(1.12)	(1.04)	8
Asset retirement expenditures	-	-	-	0.01	-	(100)
Exploration and evaluation lease expiries	-	-	-	(1.04)	(0.32)	225
Depletion, depreciation and accretion expense	(22.95)	(23.40)	(2)	(22.96)	(23.32)	(2)
Earnings before taxes	15.43	38.32	(60)	8.20	34.21	(76)
Deferred income tax provision	(5.43)	(4.96)	9	(2.86)	(3.69)	(22)
Net earnings	10.00	33.36	(70)	5.34	30.52	(83)

Capital Expenditures

Total exploration and development capital expenditures for the three and six month periods ended June 30, 2015, were $33.4 million and $117.5 million respectively, compared to $27.8 million and $99.8 million for the same periods in 2014. The expenditures are detailed below:

	Three months ended June 30, 2015	2014	% Change	Six months ended June 30, 2015	2014	% Change
	(thousands of dollars)			*(thousands of dollars)*		
Land	1,094	425	157	1,411	1,793	21
Property acquisitions	-	-	-	35,729	-	100
Geological and geophysical	10	9	11	11	77	(86)
Drilling and completions	30,772	27,125	13	77,770	89,482	(13)
Production facilities	1,538	210	632	2,583	8,409	(69)
Other	3	20	(85)	19	46	(59)
Exploration and development	33,417	27,789	20	117,523	99,807	18

In the first half of 2015, Raging River drilled a total of 96 (89.3 net) crude oil wells, all in Dodsland in southwest Saskatchewan, with a 100% success rate. In the second quarter of 2015, Raging River drilled a total of 36 (36.0 net) crude oil wells with a success rate of 100%. By comparison, the Company drilled a total of 23 (22.0 net) wells in the second quarter of 2014 and 98 (87.7 net) wells in the six month period ended June 30, 2014.

In the three months ended June 30, 2015, the Company invested a total of $33.4 million on capital expenditures including $32.3 million on drilling, completions and production facilities and $1.1 million on land and geological and geophysical costs.

During the first half of 2015, the Company spent $117.5 million on capital expenditures including $80.4 million on drilling, completions and production facilities, $35.7 million on the property acquisition that closed in the first quarter of 2015 and $1.4 million on land and geological and geophysical costs.

The Company is maintaining a capital budget of $235 million which includes $175 million of exploration and development expenditures, $20 million of waterflood and new technology capital and $40 million of acquisition capital. The capital budget will be funded from a combination of anticipated 2015 cashflow and the Company's credit facility of $300 million.

Drilling Activity

The following table summarizes our drilling results:

	Three months ended June 30, 2015 Gross	Net	2014 Gross	Net	Six months ended June 30, 2015 Gross	Net	2014 Gross	Net
Crude oil	36	36.0	22	21.0	96	89.3	97	86.7
Natural gas	-	-	-	-	-	-	-	-
Test well	-	-	-	-	-	-	-	-
Service	-	-	-	-	-	-	-	-
Dry and abandoned	-	-	1	1.0	-	-	1	1.0
Total	36	36.0	23	22.0	96	89.3	98	87.7
Success	100%	100%	96%	95%	100%	100%	96%	95%

Liquidity and Capital Resources

At June 30, 2015, the Company had net debt of $99.1 million compared to net debt of $152.2 million at December 31, 2014. For the six months ended June 30, 2015, funds flow from operations of $83.0 combined with common share equity issuances for net proceeds of $83.7 million, warrant and stock option proceeds of $3.9 million less capital expenditures of $117.5 million resulted in the ending net debt of $99.1 million. The Company expects to have adequate liquidity to fund the 2015 capital expenditure budget of $235 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

	June 30, 2015	June 30, 2014
($ thousands)		
Capital Resources		
Bank debt available	300,000	300,000
Net debt	(99,058)	(89,333)
Total capital resources available	200,942	210,667

Changes to share capital in 2015 were the following:

On February 4, 2015, the Company completed a bought deal financing for net proceeds of $83.8 million and issued 13.8 million common shares at a price of $6.40 per common share.

During the six months ended June 30, 2015, 2.3 million stock options were exercised for 1.7 million common shares on a cash-less basis and 504 thousand stock options were exercised for 504 thousand common shares for proceeds of $1.0 million.

During the six months ended June 30, 2015, 1.1 million warrants were exercised for 837 thousand common shares on a cash-less basis and 1.5 million warrants were exercised for 1.5 million common shares for proceeds of $3.0 million.

Common share information

CAPITALIZATION

Share Capital

	Three months ended June 30,		Six months ended June 30,	
Outstanding common shares	2015	2014	2015	2014
Weighted average outstanding common shares [1]				
-Basic	197,882	179,438	194,067	177,460
-Diluted	201,734	188,002	197,754	185,523
Outstanding securities at June 30, 2015				
-Common shares				198,664,895
-Common share options – average strike price of $6.40				12,654,775

(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 June 30, 2015 was approximately $1.7 billion.

	June 30, 2015
Common shares outstanding	198,664,895
Share price [1]	$8.73
Total market capitalization	$1,734,344,533

(1) Represents the closing price traded on the TSX on June 30, 2015.

As at August 11, 2015 the Company had 199,137,796 common shares outstanding.

	August 11, 2015
Outstanding securities at August 11, 2015	
-Common shares	199,137,796
-Stock options – weighted average exercise price of $6.58	12,418,107

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	121	-	3,016
Bank debt	-	54,481	-	-	54,481
Financial instruments	123	-	-	-	123
Total contractual obligations	847	56,562	121	-	57,620

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 first half of 2015.

Summary of Quarterly Results

	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13	Q3/13
Financial *(thousands of dollars except share data)*								
Petroleum and natural gas revenue	73,465	55,006	78,634	88,566	88,931	80,707	56,106	50,287
Funds flow from operations (1)	49,535	33,480	57,704	57,850	56,283	49,813	35,882	32,174
Per share - basic	0.25	0.18	0.32	0.32	0.32	0.28	0.22	0.21
- diluted	0.25	0.17	0.31	0.31	0.30	0.27	0.20	0.19
Net earnings	12,145	760	24,067	31,505	30,238	24,360	16,622	11,738
Per share - basic	0.06	0.00	0.14	0.17	0.17	0.14	0.10	0.07
- diluted	0.06	0.00	0.13	0.17	0.16	0.13	0.09	0.07
Capital expenditures, net	33,417	84,106	97,123	81,664	27,789	72,017	164,121	60,184
Shareholders' equity	602,539	587,903	496,984	470,775	437,159	405,258	379,403	286,318
Weighted average shares								
Basic	197,882	190,207	180,256	180,081	179,438	175,461	164,121	156,757
Diluted	201,734	194,986	187,394	188,442	188,002	183,417	178,729	169,485
Shares outstanding, end of period *(thousands)*								
Basic	198,655	197,206	180,332	180,209	179,890	179,213	170,914	156,757
Diluted	211,320	209,692	196,064	195,755	195,104	192,372	195,214	180,879
Operating *(6:1 boe conversion)*								
Average daily production								
Crude oil and NGLs *(bbls/d)*	12,856	12,870	12,059	10,278	9,500	9,427	7,458	5,495
Natural gas *(mcf/d)*	2,947	2,641	2,931	2,406	2,765	2,269	1,912	1,104
Barrels of oil equivalent (2) *(boe/d)*	13,347	13,310	12,548	10,679	9,960	9,805	7,777	5,679
Average selling prices(4)								
Crude oil and NGLs *($/bbl)*	60.20	46.93	70.00	92.79	101.59	93.75	80.93	98.98
Natural gas *($/mcf)*	2.59	2.73	3.60	3.74	4.41	5.69	3.28	2.43
Barrels of oil equivalent (2) *($/boe)*	60.49	45.92	68.12	90.14	98.11	91.46	78.42	96.25
Netbacks ($/boe)								
Operating								
Petroleum and natural gas revenue(4)	60.49	45.92	68.12	90.14	98.11	91.46	78.42	96.25
Realized gain (loss) on commodity contracts	0.37	1.59	4.01	0.13	(2.34)	(1.86)	(1.99)	(7.65)
Royalties	(5.86)	(4.83)	(5.33)	(8.89)	(9.63)	(8.27)	(7.02)	(8.86)
Operating expenses	(10.69)	(11.36)	(11.45)	(11.75)	(11.99)	(12.50)	(12.42)	(12.53)
Transportation expenses	(1.39)	(1.35)	(1.30)	(1.95)	(1.99)	(2.01)	(2.10)	(2.02)
Operating netback *($/boe)*	42.92	29.97	54.05	67.68	72.16	66.82	54.89	65.19
General and administrative	(1.30)	(1.37)	(1.44)	(1.39)	(1.43)	(1.47)	(1.78)	(1.85)
Financial charges	(0.83)	(0.63)	(0.71)	(0.91)	(1.19)	(1.03)	(0.76)	(0.32)
Asset retirement obligation	-	(0.02)	(0.09)	-	-	-	-	-
Current taxes	-	-	(1.82)	(6.51)	(7.45)	(7.88)	(2.20)	(0.55)
Funds flow netback(3) *($/boe)*	40.79	27.95	49.99	58.87	62.09	56.44	50.15	62.47

(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 2015, 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 2015 production, revenues, funds flow from operations and net earnings. The decrease in revenue, funds flow from operations and net earnings in the first half of 2015 is primarily due to lower commodity prices. The $35.7 million property acquisition that closed in the first quarter of 2015 was not material to the Company's operations. Please refer to the Financial and Operating Results section of this MD&A for detailed discussions of changes in the second quarter of 2015.

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. The control framework Raging River's officers used to design the Company's ICFR is the Internal Control - Integrated Framework (1992) ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). No changes were made to the Company's internal controls over financial reporting during reporting during the period from January 1, 2015 to June 30, 2015 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

Determination of cash-generating units ("CGU") and impairment

The determination of what constitutes a 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, exchange 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.

Exploration and evaluation ("E&E") assets

The application of the Company's accounting policy for E&E assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found. Judgment is also required to determine the level at which E&E is assessed for impairment; for Raging River, the recoverable amount of E&E assets is assessed at the CGU level.

Deferred income taxes

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

b) Key Sources of Estimation Uncertainty

Business combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed, which includes assessing the value of oil and natural gas properties based on the estimation of recoverable quantities of proved plus probable reserves being acquired.

Valuation of property and equipment/Reserves

The valuation of property and equipment involves the estimation of proved plus probable reserves and includes assumptions regarding future commodity prices, exchange rates, discount rates, future development costs and production and transportation costs for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property, plant and equipment. These reserve estimates are verified by third-party professional engineers, who work with information provided by the Company to establish reserve determinations in accordance with NI 51-101. Accordingly, the impact to the financial statements in future years could be material.

Asset retirement obligations

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 year when it becomes probable that there will be a future cash outflow.

Valuation of derivative financial instruments

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

Measurement of share-based compensation

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, forfeiture rates and the expected term.

Income taxes

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.

Summary of Significant Accounting Policies

The Company's accounting policies are described in Note 3 to the December 31, 2014 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.

Future accounting pronouncements

IFRS 15 Revenue from Contracts with Customers, provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework that applies to contracts with customers. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. Management is currently assessing the potential impact of the adoption of IFRS 15 on the Company's financial statements.

IFRS 9 Financial Instruments, is intended to replace IAS 39 Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. For financial liabilities designated at fair value through profit or loss, a company can recognize the portion of the change in fair value related to the change in the company's own credit risk through other comprehensive income rather than profit or loss. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. Management is currently assessing the potential impact of the adoption of IFRS 9 on the Company's financial statements.

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) (3)
Chairman & CEO, Bonterra Energy Corp.
Calgary, Alberta

RAYMOND P. MACK (1)
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)
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