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 March 7, 2016 and should be read in conjunction with the audited financial statements for the years ended December 31, 2015 and 2014 and the notes thereto. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are referenced in Canadian dollars. In addition, readers are also directed to the Company's Annual Information Form for the year ended December 31, 2015, which will be filed on SEDAR at www.sedar.com prior to March 30, 2016.

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 2016 capital budget including expected capital expenditures, expectations that the Company will have adequate liquidity to fund operations and capital expenditures and the timing and funding thereof and expected use of proceeds from the recently announced bought deal financing, the exercise of the over-allotment option under the recently announced bought deal financing, and the timing of completion of the bought deal financing. 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, imprecision of reserve estimates, changes in general economic conditions, whether farm-in and farm-out opportunities result in agreements and other factors more fully described from time to time in the reports and filings made by the Company with securities regulatory authorities including the Company's most recent annual information form. 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 annual 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 December 31,		Year ended, December 31,	
	2015	2014	2015	2014
	(thousands of dollars)			
Cash flow from operating activities	38,549	71,621	138,228	229,820
Changes in non – cash working capital	2,159	(13,917)	29,123	(8,170)
Funds flow from operations	40,708	57,704	167,351	221,650

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.

Oil and Gas Metrics

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

This MD&A contains a number of oil and gas metrics, including finding, development and acquisition costs and recycle ratio, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods. Finding, development and acquisition costs are used as a measure of capital efficiency. The calculation includes all capital costs (exploration, development and acquisition capital) for that period plus the change in future development capital for that period. This total capital including the change in the future development capital is then divided by the change in reserves for that period incorporating all revisions and production for that same period. The recycle ratio was calculated by dividing operating netback per boe by the finding, development and acquisition costs for the year.

This MD&A discloses unbooked drilling locations. Unbooked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Unbooked locations have been identified by management as an estimation of our multiyear drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations may have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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 in the Viking oil resource play in western Canada, being primarily located in the Dodsland area in southwestern Saskatchewan and southeast Alberta.

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

FOURTH QUARTER 2015 HIGHLIGHTS

- Achieved another quarterly production record with average production of 14,771 boe/d (91% oil) representing an increase of 18% over the comparable period in 2014. This represents a 5% production per share increase from the fourth quarter of 2014.

- Achieved funds flow from operations of $40.7 million ($0.20/share basic)

- Achieved our 16th consecutive quarter of earnings despite a year over year drop of 48% in the benchmark WTI price. Fourth quarter earnings were $5.1 million.

- The Company's exploration and development expenditures for the quarter were $43.5 million. A total of 63.0 net Viking wells were drilled at a 98% success rate. Average on stream costs during the quarter were approximately $680,000 per well representing a 25% cost reduction from the average costs seen in 2014 and a 3% quarter over quarter decrease in on stream costs.

- Raging River generated top decile operating netbacks of $32.21/boe and funds flow netbacks of $29.96/boe in addition to earnings of $3.77 per boe.

- Achieved our 10th consecutive quarterly decrease in operating and transportation costs to $10.28/boe, a 19.4% reduction from the comparable quarter of 2014 and a 2.2% reduction quarter over quarter.

- Closed the $125.8 million previously announced corporate acquisition of Anegada Energy Corp. ("Anegada"). The acquisition includes 2,750 boe/d (58% light oil) of estimated 2016 average production and 50 net sections of highly prospective land targeting Viking oil in areas complementary to Raging River's existing Viking assets.

- Maintained balance sheet strength with fourth quarter exit net debt of $139.9 million representing 0.86 times debt to the fourth quarter annualized cash flow.

YEAR ENDED DECEMBER 31, 2015

- Increased average production to 13,715 boe/d, a 28% increase (15% per share) over 2014 production of 10,755 boe/d.

- The Company invested a total of $339.2 million consisting of $171 million of development capital and $168.2 million of acquisition capital into the expansion and development of the Viking play.

- Executed a $171 million exploration and development program drilling a total of 233 (216.9 net) Viking wells with a 99% success rate.

- Achieved a 16.9% reduction in operating and transportation costs to $11.36/boe from the year ended December 31, 2014.

- Attained top decile general and administrative costs of $1.30/boe, a 9% decrease from the comparable period in 2014.

- Proved plus probable reserves increased 20% to 76.4 mmboe (90% oil) and proven reserves increased 15% to 57.4 mmboe (92% oil).

- Finding, development and acquisition ("FD&A") costs including the change in future development capital were $16.59/boe on a total proved plus probable basis resulting in a recycle ratio of 2.14 times.

- Total net undeveloped land holdings increased 26% to 279,628 acres in our core Viking prospect areas in southwest Saskatchewan and southeast Alberta.

SUBSEQUENT TO THE YEAR ENDED DECEMBER 31, 2015

- On February 17, 2016, Raging River entered a bought deal financing to issue 11,000,000 common shares at a price of $8.65 per common share for gross proceeds of $95.2 million. The underwriters have provided notice of their intention to exercise in full the over-allotment option granted to them to purchase an additional 1,500,000 common shares at a price of $8.65 per common share at closing.

<u>Petroleum and Natural Gas Revenue</u>

	Three months ended December 31, 2015	Three months ended December 31, 2014	Percent Change	Year ended December 31, 2015	Year ended December 31, 2014	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Liquids revenue	62,129	77,497	(20)	251,899	332,164	(24)
Natural gas revenue	736	970	(24)	2,719	4,069	(33)
Royalty revenue	78	167	(53)	314	605	(48)
	62,943	78,634	(20)	254,932	336,838	(24)
Operating: (6:1 boe conversion)						
Average daily production						
Liquids (bbls/d)	14,194	12,059	18	13,235	10,323	28
Natural gas (mcf/d)	3,461	2,931	18	2,877	2,594	11
Barrels of oil equivalent (boe/d)	14,771	12,548	18	13,715	10,755	28
Raging River average sales price						
Liquids ($/bbl)	47.64	70.00	(32)	52.21	88.32	(41)
Natural gas ($/mcf)	2.31	3.60	(36)	2.59	4.30	(40)
Barrel of oil equivalent ($/boe)	46.32	68.12	(32)	50.93	85.80	(41)
Average Benchmark Prices						
Crude Oil - WTI (US$/bbl)	42.18	73.15	(42)	48.80	93.00	(48)
Crude Oil – MSW	52.87	75.59	(30)	57.14	94.38	(39)
Natural gas - AECO	2.48	3.63	(32)	2.70	4.50	(40)
Exchange rate (US$/Cdn$)	0.75	0.88	(15)	0.78	0.91	(14)

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 significant decline in the WTI price was only slightly offset by the weak Canadian dollar in the fourth quarter of 2015, resulting in a lower realized price for the Company. Raging River's average quality adjustment to MSW pricing during the fourth quarter of 2015 decreased slightly to $5.23/bbl compared to $5.59bbl in the fourth quarter of 2014. The Company's liquids price averaged $47.64/bbl for the fourth quarter of 2015, down 32% from $70.00/bbl in the fourth quarter of 2014.

The significant decline in the WTI price throughout 2015 was partially offset by devaluation of the Canadian dollar relative to the US dollar. This resulted in the Company realizing an average liquids price of $52.21/bbl for the year ended 2015, down 41% from an average price of $88.32/bbl received in 2014. Raging River's average quality adjustment to MSW narrowed to $4.93/bbl in 2015 from $6.06/bbl in the comparable period of 2014.

The AECO natural gas price declined in the fourth quarter and in the year ended December 31, 2015 due to above average input into storage from an oversupplied market and warmer weather reducing demand, 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 fourth quarter and year ended December 31, 2015 was $2.31 per mcf and $2.59 per mcf respectively, compared to $3.60 per mcf and $4.30 per mcf for the same periods in 2014.

During the fourth quarter of 2015, the Company drilled a total of 70 (63.0 net) crude oil wells resulting in 69 (62.0 net) crude oil wells and 1 (1.0 net) service well, with a 98% success rate. In the year ended December 31, 2015, Raging River drilled a total of 233 (216.9 net) wells resulting in 231 (215.2 net) crude oil wells, 1 (1.0 net) service well and 1 (0.7 net) dry hole for an overall success rate of 99%.

Production	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13
Liquids (bbls/d)	14,194	13,009	12,856	12,870	12,059	10,278	9,500	9,427	7,458
Natural gas (mcf/d)	3,461	2,454	2,947	2,641	2,931	2,406	2,765	2,269	1,912
Total (boe/d)	14,771	13,418	13,347	13,310	12,548	10,679	9,960	9,805	7,777
% increase over prior quarter	10%	1%	-	6%	18%	7%	2%	26%	37%
Production per 1 million shares	72.8	67.2	67.4	70.0	69.6	59.3	55.5	55.9	47.4
Per share % increase (decrease) over prior quarter	8%	-	(4%)	1%	17%	7%	(1%)	18%	31%

Quarter over quarter, production in the fourth quarter of 2015 increased to 14,771 boe/d from 13,418 boe/d, an increase of 10%. The Company's production for the fourth quarter of 2015 increased to 14,771 boe/d from 12,548 boe/d in the fourth quarter of 2014, an increase of 18%. The year over year increase of 28% was attributable to a successful drilling program in 2015 and 2014 and the property acquisition in the first quarter of 2015. With the Anegada acquisition closing late in December 2015, there was an immaterial impact to 2015 production levels from corporate acquisitions in 2015.

Petroleum and natural gas revenue in the three month period December 31, 2015 was $62.9 million as compared to $78.6 million in the comparable period of 2014. This decrease was attributable to a 32% decrease in commodity pricing that was partially offset by an 18% increase in production volumes.

Petroleum and natural gas revenues for the year ended December 31, 2015 were $254.9 million, as compared to $336.8 million in the comparable period of 2014, representing a decrease of 24%. This decrease in revenue is again attributed to a 41% decline in commodity prices that was partially offset by a 28% 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 March 7, 2016 the Company has the following price contracts in place by quarter:

2016

Q1

Crude oil	Differential	Jan 2016 – Mar 2016	1,500 bbls/d	Cdn $4.65/bbl	WTI/Edm
Natural gas	Fixed	Jan 2016 – Mar 2016	2,333 GJs/d	Cdn $2.39/GJ	AB-NIT

Q2

Crude oil	Differential	Apr 2016 – Jun 2016	1,500 bbls/d	Cdn $4.65/bbl	WTI/Edm
Natural gas	Fixed	Apr 2016 – Jun 2016	2,500 GJs/d	Cdn $2.39/GJ	AB-NIT

Q3

Crude oil	Differential	Jul 2016 – Sept 2016	1,500 bbls/d	Cdn $4.65/bbl	WTI/Edm
Natural gas	Fixed	Jul 2016 – Sept 2016	2,500 GJs/d	Cdn $2.41/GJ	AB-NIT

Q4

Crude oil	Differential	Oct 2016 – Dec 2016	1,500 bbls/d	Cdn $4.65/bbl	WTI/Edm
Natural gas	Fixed	Oct 2016 – Dec 2016	2,500 GJs/d	Cdn $2.45/GJ	AB-NIT

Realized & unrealized gain/loss on financial instruments

The realized gain/loss represents the commodity contracts settled during fourth quarter and year ended December 31, 2015. As the oil commodity contracts are referenced to the WTI and settled in Canadian dollars, the realized gains and losses fluctuate based on changes in the WTI price and $US/$Cdn exchange rate.

The significant decline in the WTI price in 2015 was only partially offset by the weak Canadian dollar which resulted in realized gains for the quarter and year ended December 31, 2015. For the three month period ended December 31, 2015, the Company realized gains of $1.2 million (three months ended December 31, 2014: realized gains of $4.6 million) and for the year ended December 31, 2015, the Company recorded a $4.6 million gain (year ended December 31, 2014: realized gains of $991 thousand).

As of December 31, 2015, the fair value of Raging River's outstanding commodity contracts is an unrealized asset of $215 thousand as reflected in the annual 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 December 31, 2015, 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 December 31, 2015. The unrealized loss of $2.3 million represents the fair value change of the underlying commodity contracts to be settled in the future. In comparison, an unrealized gain of $4.0 million was recorded for the year ended December 31, 2014.

In the fourth quarter of 2015 due to a decline in the WTI price, the Company had unrealized losses of $735 thousand, compared to unrealized gains of $1.3 million in the fourth quarter of 2014.

Royalties

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2015	2014	Change	2015	2014	Change
	(thousands of dollars)			*(thousands of dollars)*		

Crown	1,288	1,606	(20)	5,192	8,953	(42)
Saskatchewan resource surcharge	1,342	1,497	(10)	4,544	5,825	(22)
Freehold and GORR	3,782	3,046	24	15,157	16,125	(6)
	6,412	6,149	4	24,893	30,903	(19)
Percent of total revenue	10.2%	7.8%	31	9.8%	9.2%	7
Per boe ($)	4.72	5.33	(11)	4.97	7.87	(37)

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and Saskatchewan resource surcharge. Royalties increased to $6.4 million in the fourth quarter of 2015 from $6.1 million in the fourth quarter of 2014, primarily as a result of an 18% increase in production volumes. On a per boe basis, royalties decreased 11% to $4.72/boe in the fourth quarter of 2015 from the comparable quarter primarily due to the 32% decline in commodity pricing.

During the year ended December 31, 2015, royalties decreased 19% to $24.9 million from $30.9 million in the comparable period. The decrease is primarily a result of a 41% decrease in commodity pricing. Royalties on a per boe basis decreased in 2015 to $4.97/boe from $7.87/boe again due to the 41% decline in commodity pricing.

Operating Expenses

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2015	2014	Change	2015	2014	Change
Total operating costs ($000's)	12,124	13,221	(8)	50,002	46,664	7
Percent of total revenue	19.3%	16.8%	15	19.6%	13.9%	41
Per boe ($)	8.92	11.45	(22)	9.99	11.89	(16)

Operating expenses decreased to $12.1 million in the fourth quarter of 2015 from $13.2 million in the fourth quarter of 2014. The decrease in operating costs in the fourth quarter of 2015 was a result of achieving cost reduction initiatives and reduced costs from warmer winter weather that was partially offset by the 18% increase in production volumes. During the year ended December 31, 2015, operating expenses increased 7% to $50.0 million from $46.7 million in the comparable period.

Operating costs averaged $8.92/boe in the fourth quarter of 2015 and $9.99/boe in the year ended December 31, 2015. This represents a decrease of 22% or $2.53/boe from $11.45/boe in the fourth quarter of 2014 and a decrease of 16% or $1.90/boe from $11.89/boe in the year ended December 31, 2014. Operating costs per boe decreased in both the fourth quarter and year ended December 31, 2015, due to mild winter conditions in 2015 as compared to 2014, a significant component of operating costs being fixed with increased production, and achieving cost reductions.

Transportation Expenses

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2015	2014	Change	2015	2014	Change
Total transportation costs ($000's)	1,842	1,499	23	6,838	6,984	(2)
Percent of total revenue	2.9%	1.9%	53	2.7%	2.1%	29
Per boe ($)	1.36	1.30	5	1.37	1.78	(23)

Transportation expenses relate to the cost of transporting natural gas and hauling crude oil to the point of sale. Transportation costs of $1.8 million in the fourth quarter of 2015 compared to $1.5 million in the fourth quarter of 2014 due to the 18% increase in production volumes. During the year ended December 31, 2015, transportation costs decreased 2% to $6.8 million from $6.9 million in the comparable period.

Transportation costs averaged $1.36/boe in the fourth quarter of 2015 and $1.37/boe in the year ended December 31, 2015. This is an increase of 5% from $1.30/boe in the fourth quarter of 2014 and a decrease of 23% from $1.78/boe in the year ended December 31, 2014. Transportation costs per boe remained flat quarter over quarter and decreased in the year ended December 31, 2015, due to a larger portion of our clean oil being transported by pipeline, which has a lower cost per boe, and cost optimization in trucking charges.

General and Administrative ("G&A") Expenses

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2015	2014	Change	2015	2014	Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	3,548	2,631	35	10,692	8,687	23
Overhead recoveries	(768)	(275)	179	(1,508)	(836)	80
Capitalized G&A	(940)	(693)	36	(2,673)	(2,228)	20
	1,840	1,663	11	6,511	5,623	16
Percent of total revenue	2.9%	2.1%	38	2.6%	1.7%	53
Per boe ($)	1.35	1.44	(6)	1.30	1.43	(9)

The Company incurred gross G&A expenses of $3.5 million and $10.7 million, respectively, during the fourth quarter and year ended December 31, 2015. Increased G&A costs before recoveries and capitalization were mainly the result of increased employee related costs including office rent, head office staff compensation and technical software to accommodate the Company's capital expenditure program and the larger operations resulting from increases in production.

Net G&A expenses incurred were $1.8 million or $1.35 per boe and $6.5 million or $1.30 per boe, respectively, during the fourth quarter and year ended December 31, 2015. The decrease in net G&A per boe from the comparable periods is a result of continued G&A efficiencies achieved combined with higher production levels.

Financial Charges

	Three months ended December 31,		Percent	Year ended December 31,		Percent
	2015	2014	Change	2015	2014	Change
Financial charges ($000's)	1,148	818	40	3,786	3,697	2
Percent of total revenue	1.8%	1.0%	80	1.5%	1.1%	36
Per boe ($)	0.84	0.71	18	0.76	0.94	(19)

Financial charges during the fourth quarter and year ended December 31, 2015, were $1.1 million and $3.8 million respectively compared to $818 thousand and $3.7 million respectively for 2014. Financial charges remained consistent in the year ended December 31, 2015 compared to 2014. The Company's financial charges increased in the fourth quarter of 2015 compared to 2014 due to carrying higher average debt levels. As at December 31, 2015, the Company had drawn $108.9 million against the available credit facilities of $300 million.

Stock-based Compensation

	Three months ended December 31, 2015	Three months ended December 31, 2014	Percent Change	Year ended December 31, 2015	Year ended December 31, 2014	Percent Change
Stock based compensation ($000's)	1,421	1,423	-	5,470	4,747	15
Percent of total revenue	2.3%	1.8%	28	2.1%	1.4%	50
Per boe ($)	1.05	1.23	(15)	1.09	1.21	(10)

As at December 31, 2015, the Company has a total of 9.6 million stock options outstanding with a weighted average fair value of $2.78 per option. Stock based compensation expense during the fourth quarter and year ended December 31, 2015, were $1.4 million and $5.5 million respectively compared to $1.4 million and $4.7 million respectively for 2014. Stock based compensation expense increased in the year ended December 31, 2015 due to amortization of expense relating to additional stock options granted to new employees.

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 December 31, 2015	Three months ended December 31, 2014	Percent Change	Year ended December 31, 2015	Year ended December 31, 2014	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion and depreciation	29,809	26,405	13	112,902	90,628	25
Exploration and evaluation lease expiries	-	-	-	2,512	581	332
Accretion	300	229	31	1,094	752	45
	30,109	26,634	13	116,508	91,961	27
Percent of total revenue	47.8%	33.9%	41	45.7%	27.3%	67
Per boe ($) – Depletion and depreciation	22.16	23.07	(4)	22.77	23.28	(2)
Per boe ($) – Exploration and evaluation lease expiries	-	-	-	0.50	0.15	233

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 during the fourth quarter and year ended December 31, 2015, were $29.8 million and $112.9 million respectively compared to $26.4 million and $90.6 million respectively for 2014. The increase in the depletion and depreciation expense in both the fourth quarter and year ended December 31, 2015, is due to the increase in production volumes combined with a significant increase to the capital base from capital expenditures and acquisitions.

Depletion per boe remained relatively constant in the fourth quarter of 2015 and year ended December 31, 2015 compared to 2014 as significant capital additions were offset by significant reserve additions and a reduction of $43.9 million in future development costs. Total proved plus probable reserves grew to 76.4 million boe, a 20% increase over the December 31, 2014 reserves of 63.6 million boe. Future development costs of $746.8 million have been included in the capital base used in the calculation and salvage values of $21.8 million have been excluded in the calculation.

Accretion increased in the fourth quarter of 2015 to $300 thousand from $229 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 2.2%. It will continue to increase with the passage of time and the increases in asset retirement obligations.

During the year ended December 31, 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 for the year ended December 31, 2014. Saskatchewan crown land leases come up for renewal annually in the first quarter of the year.

Asset Retirement Obligations

As at December 31, 2015, the asset retirement obligation of the Company was $64.9 million. The Company recorded an increase of $22.4 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 in 2015, the corporate and property acquisitions and an upward revision to the estimate. The revision to estimated asset retirement obligations of $8.7 million (December 31, 2014 - $10.6 million) in the year was due to a combination of discounting future cost estimates at a lower rate than in prior periods which resulted in an increase of $1.7 million and the revaluation of asset retirement obligations acquired throughout the year. 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 $7.0 million.

Income Taxes

Income tax expense for the year ended December 31, 2015 was $14.3 million of deferred income taxes for an effective tax provision rate of 33%. In 2015, the province of Alberta increased its corporate tax rate to 12% from 10% which resulted in a future rate adjustment that was recorded in the current period. During the period ended December 31, 2015, Raging River was not subject to any current corporate income tax due to the decline in commodity pricing. The federal tax pools are as follows:

($ thousands)	Estimated balance at January 1, 2016
Canadian oil and gas property expense	195,591
Canadian development expense	283,375
Canadian exploration expense	6,924
Undepreciated capital cost	144,089
Non-capital losses	8,980
Share issue costs	7,163
Total	646,122

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 year ended December 31, 2015, Raging River recorded funds flow from operations of $167.4 million and net earnings of $28.9 million. This decrease from the 2014 results with funds flow from operations of $221.7 million and net earnings of $110.2 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 December 31,		Percent	Year ended December 31,		Percent
	2015	2014	Change	2015	2014	Change
	($/boe)			*($/boe)*		
Petroleum and natural gas revenue	46.32	68.12	(32)	50.93	85.80	(41)
Realized gain on commodity contracts	0.89	4.01	(78)	0.91	0.25	264
Royalties	(4.72)	(5.33)	(11)	(4.97)	(7.87)	(37)
Net revenue	42.49	66.80	(36)	46.87	78.18	(40)
Operating expenses	(8.92)	(11.45)	(22)	(9.99)	(11.89)	(16)
Transportation expenses	(1.36)	(1.30)	5	(1.37)	(1.78)	(23)
Operating netback	32.21	54.05	(40)	35.51	64.51	(45)
General and administrative expenses	(1.35)	(1.44)	(6)	(1.30)	(1.43)	(9)
Financial charges	(0.84)	(0.71)	18	(0.76)	(0.94)	(19)
Asset retirement expenditures	(0.06)	(0.09)	(33)	(0.02)	(0.03)	(33)
Current taxes	-	(1.82)	100	-	(5.65)	100
Funds flow from operations	29.96	49.99	(40)	33.43	56.46	(41)
Unrealized gain (loss) on financial instruments	(0.54)	1.14	(147)	(0.46)	1.02	(145)
Stock-based compensation expense	(1.05)	(1.23)	(15)	(1.09)	(1.21)	(10)
Asset retirement expenditures	0.06	0.09	(33)	0.02	0.03	(33)
Exploration and evaluation lease expiries	-	-	-	(0.50)	(0.15)	233
Depletion, depreciation and accretion expense	(22.16)	(23.07)	(4)	(22.77)	(23.28)	(2)
Earnings before deferred taxes	6.27	26.92	(77)	8.63	32.87	(74)
Deferred income tax provision	(2.50)	(6.06)	(59)	(2.85)	(4.81)	(41)
Net earnings	3.77	20.86	(82)	5.78	28.06	(79)

Capital Expenditures

During 2015, the Company invested a total of $339.2 million consisting of $171 million of development capital and $168.2 million of acquisition capital into the expansion and development of the Viking play. This investment includes the issuance of 11.7 million common shares at $8.15 per common share as consideration for the Anegada acquisition. The Company also assumed $30.2 million net debt as part of the acquisition consideration.

	Three months ended December 31, 2015	2014	Percent Change	Year ended December 31, 2015	2014	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Land	1,715	4,065	(58)	2,946	6,268	(53)
Property acquisitions	(213)	-	(100)	39,731	4,701	745
Geological and geophysical	9	119	(92)	9	213	(96)
Drilling and completions	30,314	86,681	(65)	128,891	247,936	(48)
Facilities and equipping	11,661	6,248	87	39,173	19,364	102
Other	8	10	(20)	28	112	(75)
Exploration and development	43,494	97,123	(55)	210,778	278,594	(24)
Corporate acquisitions - cash	32,790	-	100	32,790	-	100
Total capital expenditures	76,284	97,123	(21)	243,568	278,594	(13)
Equity issuance on corporate acquisition	-	-	-	95,623	-	100
Total invested capital	76,284	97,123	(21)	339,191	278,594	22

Exploration and development program

In the year ended December 31, 2015, Raging River drilled a total of 233 (216.9 net) crude oil wells, primarily in the greater Dodsland area in southwest Saskatchewan, with a 99% success rate. This included 231 (215.2 net) crude oil wells, 1 (1.0 net) service test well and 1 (0.7 net) dry hole. By comparison, the Company drilled a total of 294 (248.8 net) wells in the year ended December 31, 2014 at a 98% success rate.

During the year ended December 31, 2015, the Company spent $210.8 million on capital expenditures including $168.1 million on drilling and completion activities and $3.0 million on land.

In the three months ended December 31, 2015, the Company invested a total of $43.5 million on capital expenditures including $42 million on development activities and $1.7 million on land.

Corporate and property acquisitions

On December 17, 2015, Raging River completed the Anegada acquisition, consisting of 2,750 boe/d (58% light oil) of production and 50 net sections land targeting Viking oil. The consideration for the acquisition was $125.8 million comprised of the issuance of approximately 11.7 million Raging River common shares issued at a deemed value of $8.15 per common share and the assumption of $30.2 million of net debt.

On December 3, 2015, the Company completed a minor acquisition of a private corporation in the Dodsland area of southwest Saskatchewan for cash consideration of $3.3 million. Production associated with these lands includes 15 bbls/d of royalty production and 20 bbls/d of vertical well production in addition to approximately 50 net unbooked Viking drilling locations.

On February 11, 2015, Raging River completed the acquisition of Viking light oil assets consisting of approximately 600 boe/d (100% light oil) of production and 30 net section of prospective lands targeting Viking oil for consideration of $35.5 million after closing adjustments.

2016 capital budget

The Company’s Board of Directors has approved 2016 exploration and development budget of $150 - $160 million. Raging River has allocated $141 million to drilling, completions and equipping, $3 million to waterflood and the remaining $6 million to land, seismic and maintenance capital. This budget will be funded from anticipated 2016 cash flow combined with the Company's existing credit facilities of $300 million.

Subsequent to year-end, the Company entered into a bought deal financing, the gross proceeds of $108.1 million (including the gross proceeds from the exercise by the underwriters of the over-allotment option in full) of which are anticipated to be used to repay a portion of the outstanding indebtedness under the Company's credit facilities which will be redrawn to fund the Company's 2016 capital expenditure program and for general corporate purposes (Refer to Subsequent Events note). The financing is expected to close on March 9, 2015.

Land Holdings

We have evaluated our undeveloped land holdings internally. This internal evaluation estimated the fair market value of our 279,628 net acres of undeveloped land holdings as at December 31, 2015, at $135 million. For purposes of the internal evaluation "fair market value" is defined as the price which we believe could be reasonably expected to be received for the undeveloped lands in an arm's length transaction. In order to determine fair market value, we considered a number of factors including a) current prices being paid for crown lands in the same area b) terms and conditions, expressed in monetary terms of recent farm-in and/or work commitments and the degree of exploration activity in each area, and c) recent industry sales of similar properties in the same general area. In areas where current prices or other pertinent information was not available, we used our best judgment.

During 2015, Raging River significantly increased its undeveloped land base, targeting the Viking oil play in both southwest Saskatchewan and southeast Alberta. A total of 57,735 net acres of undeveloped land were acquired through land sales, property acquisitions completed throughout 2015 and the corporate acquisitions that closed in late 2015. The following table summarizes our developed and undeveloped land holdings (in acres) as at December 31, 2015.

	Undeveloped		Developed		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Saskatchewan	260,980	213,807	66,398	56,588	327,378	270,395
Alberta	67,870	65,821	16,889	16,089	84,759	81,910
Total	328,850	279,628	83,287	72,677	412,137	352,305

(1) *"Gross" means the total number of acres in which we hold an interest.*
(2) *"Net" means the total area in which Raging River has an interest multiplied by Raging River's working interest.*

Drilling Activity

The following table summarizes our drilling results:

	Three months ended December 31,				Year ended December 31,			
	2015		2014		2015		2014	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil	69	62.0	106	88.1	231	215.2	288	244.0
Natural gas	-	-	-	-	-	-	-	-
Test well	-		-	-	-	-	1	0.5
Service	1	1.0	-	-	1	1.0	-	-
Dry and abandoned	-	-	3	2.8	1	0.7	5	4.3
Total	70	63.0	109	90.9	233	216.9	294	248.8
Success	99%	98%	97%	97%	99%	99%	98%	98%

Liquidity and Capital Resources

At December 31, 2015, the Company had net debt of $139.9 million compared to net debt of $152.2 million at December 31, 2014. For the year ended December 31, 2015, funds flow from operations of $167.4 combined with common share equity issuances and warrant and stock option proceeds for net proceeds of $88.8 million, less capital expenditures of $243.6 million and $0.3 million of working capital adjustments related to acquisitions, resulted in the ending net debt of $139.9 million.

The Company expects to have adequate liquidity to fund the updated 2016 capital expenditure budget of $150 - $160 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.

The Company's credit facilities consist of a $280 million extendible revolving credit facility with a syndicate of lenders and a $20 million extendible operating credit facility. The credit facilities have a revolving period currently expiring on April 28, 2016, extendible annually at the request of the Company, subject to approval of the lenders, and repayable one year after the expiry of the revolving period. The credit facilities are secured by a first floating charge debenture in the amount of $500 million over all of the Company's assets and bear interest at rates that fluctuate, depending on the Company's debt to cash flow ratio (as defined in the agreement governing the credit facilities). Repayments of principal are not required until the maturity date, provided that the borrowings under the credit facilities do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties under the credit facilities. As at the date hereof the Company is in compliance with all covenants under the credit facilities. The borrowing base of the credit facilities is subject to a semi-annual redetermination on or before April 30 and October 31 of each year.

Subsequent to year end, the Company entered into a bought deal financing to issue 11,000,000 common shares at a price of $8.65 per common share and pursuant to such financing granted the underwriters an over-allotment option to purchase an additional 1,500,000 common shares at a price of $8.65 per common share. The net proceeds of $103.0 million (Including the net proceeds from the exercise by the underwriters of the over-allotment option in full) will be used to repay a portion of outstanding indebtedness under the Company's credit facilities which will be redrawn to fund the Company's 2016 capital expenditure program and for general corporate purposes (Refer to Subsequent Events note). The financing is expected to close on March 9, 2016.

Capital Resources

	December 31, 2015	2014
($ thousands)		
Capital Resources		
Bank debt available	300,000	300,000
Net debt	(139,943)	(152,250)
Total capital resources available	160,057	147,750

Changes to share capital in 2015 were the following:

On December 17, 2015, the Company completed the corporate acquisition of Anegada through the issuance of 11.7 million common shares issued at the deemed price of $8.15 per share.

On February 4, 2015, the Company completed a bought deal financing for gross proceeds of $88.3 million and issued 13.8 million common shares at a price of $6.40 per common share, which included the exercise in full of the over-allotment granted to the underwriters.

During the year ended December 31, 2015, 5.6 million stock options were exercised for 4.0 common shares on a cash-less basis and 1.2 million stock options were exercised for 1.2 million common shares for proceeds of $2.7 million.

During the year ended December 31, 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 December 31,		Year ended December 31,	
Outstanding common shares	2015	2014	2015	2014
Weighted average outstanding common shares [(1)]				
-Basic	202,977	180,256	197,701	178,826
-Diluted	203,897	187,394	198,601	186,602
Outstanding securities at December 31, 2015				
-Common shares				213,420,900
-Common share options – average strike price of $8.18				9,629,836

(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 December 31, 2015 was approximately $1.8 billion.

	December 31, 2015
Common shares outstanding	213,420,900
Share price [(1)]	$8.37
Total market capitalization	$1,786,332,933

(1) Represents the last price traded on the Toronto Stock Exchange on December 31, 2015.

As at March 7, 2016 the Company had 213,487,637 common shares outstanding.

	March 7, 2016
Outstanding securities at March 7, 2016	
-Common shares	213,487,637
-Stock options – weighted average exercise price of $8.23	9,950,335

Subsequent Events

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

Financing

On February 17, 2016, the Company announced that it has entered into a bought deal financing to issue 11,000,000 common shares at a price of $8.65 per common share for gross proceeds of $95.2 million. The underwriters were granted an option to purchase up to an additional 1,500,000 common shares at a price of $8.65 per common share to cover over-allotments, exercisable in whole or in part at any time until 30 days after the closing date. The underwriters have provided notice of their intention to exercise the over-allotment option in full at closing. The gross proceeds that will be raised are approximately $108.1 million, which includes the gross proceeds from the exercise of the over-allotment option. The bought deal financing is expected to close on March 9, 2016.

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	780	2,079	-	-	2,859
Bank debt	-	108,897	-	-	108,897
Total contractual obligations	780	110,976	-	-	111,756

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 year ended December 31, 2015.

Selected Annual Information

	2015	2014	2013
Financial *(thousands of dollars except share data)*			
Average production volumes	13,715	10,755	5,665
Petroleum and natural gas revenue	254,932	336,838	175,808
Funds flow from operations (1)	167,352	221,650	116,967
Per share - basic	0.85	1.24	0.74
- diluted	0.84	1.19	0.69
Net earnings	28,919	110,170	43,412
Per share - basic	0.15	0.62	0.27
- diluted	0.15	0.59	0.26
Total assets	1,029,034	765,332	550,746
Net debt(1)	139,943	152,250	96,322
Weighted average shares *(thousands)*			
Basic	197,701	178,826	158,613
Diluted	198,601	186,602	170,236

(1) Funds flow from operations and net debt do not have a standardized meaning under GAAP. Refer to non-GAAP measures in this MD&A.

The Company's petroleum and natural gas revenue, funds flow from operations and total assets have increased for the years 2013 to 2014 due to increased production volumes from the Company's successful capital program combined with corporate and property acquisitions completed during these periods. The decrease in revenue, funds flow from operations and net earnings in the year ended December 31, 2015 is primarily due to lower commodity prices.

Summary of Quarterly Results

	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14
Financial *(thousands of dollars except share data)*								
Petroleum and natural gas revenue	62,943	63,518	73,465	55,006	78,634	88,566	88,931	80,707
Funds flow from operations (1)	40,708	43,630	49,535	33,480	57,704	57,850	56,283	49,813
Per share - basic	0.20	0.22	0.25	0.18	0.32	0.32	0.32	0.28
- diluted	0.20	0.22	0.25	0.17	0.31	0.31	0.30	0.27
Net earnings	5,120	10,893	12,145	760	24,067	31,505	30,238	24,360
Per share - basic	0.03	0.05	0.06	0.00	0.14	0.17	0.17	0.14
- diluted	0.03	0.05	0.06	0.00	0.13	0.17	0.16	0.13
Capital expenditures, net	76,284	49,760	33,417	84,106	97,123	81,664	27,789	72,017
Shareholders' equity	719,213	616,834	602,539	587,903	496,984	470,775	437,159	405,258
Weighted average shares (thousands)								
Basic	202,977	199,576	197,882	190,207	180,256	180,081	179,438	175,461
Diluted	203,897	201,648	201,734	194,986	187,394	188,442	188,002	183,417
Shares outstanding, end of period *(thousands)*								
Basic	213,421	200,319	198,655	197,206	180,332	180,209	179,890	179,213
Diluted	223,051	211,265	211,320	209,692	196,064	195,755	195,104	192,372
Operating *(6:1 boe conversion)*								
Average daily production								
Crude oil and NGLs *(bbls/d)*	14,194	13,009	12,856	12,870	12,059	10,278	9,500	9,427
Natural gas *(mcf/d)*	3,461	2,454	2,947	2,641	2,931	2,406	2,765	2,269
Barrels of oil equivalent (2) *(boe/d)*	14,771	13,418	13,347	13,310	12,548	10,679	9,960	9,805
Average selling prices(4)								
Crude oil and NGLs *($/bbl)*	47.64	52.54	60.20	46.93	70.00	92.79	101.59	93.75
Natural gas *($/mcf)*	2.31	2.82	2.59	2.73	3.60	3.74	4.41	5.69
Barrels of oil equivalent (2) *($/boe)*	46.32	51.45	60.49	45.92	68.12	90.14	98.11	91.46
Netbacks ($/boe)								
Operating								
Petroleum and natural gas revenue(4)	46.32	51.45	60.49	45.92	68.12	90.14	98.11	91.46
Realized gain (loss) on commodity contracts	0.89	0.80	0.37	1.59	4.01	0.13	(2.34)	(1.86)
Royalties	(4.72)	(4.52)	(5.86)	(4.83)	(5.33)	(8.89)	(9.63)	(8.27)
Operating expenses	(8.92)	(9.14)	(10.69)	(11.36)	(11.45)	(11.75)	(11.99)	(12.50)
Transportation expenses	(1.36)	(1.37)	(1.39)	(1.35)	(1.30)	(1.95)	(1.99)	(2.01)
Operating netback *($/boe)*(5)	32.21	37.22	42.92	29.97	54.05	67.68	72.16	66.82
General and administrative	(1.35)	(1.18)	(1.30)	(1.37)	(1.44)	(1.39)	(1.43)	(1.47)
Financial charges	(0.84)	(0.71)	(0.83)	(0.63)	(0.71)	(0.91)	(1.19)	(1.03)
Asset retirement obligation	(0.06)	-	-	(0.02)	(0.09)	-	-	-
Current taxes	-	-	-	-	(1.82)	(6.51)	(7.45)	(7.88)
Funds flow netback(3) *($/boe)*	29.96	35.33	40.79	27.95	49.99	58.87	62.09	56.44

(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, and current taxes.
(4) Excludes unrealized risk management contracts.
(5) Operating netback is calculated as revenues received less royalties, operating and transportation costs and realized gains or losses on commodity 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 production, revenues, funds flow from operations and net earnings. The decrease in revenue, funds flow from operations and net earnings experienced in each quarter in 2015 is primarily due to lower commodity prices. With the closing of the Anegada acquisition late in December 2015, there were minimal impact on operations and financial results for both the fourth quarter and year ended 2015. Please refer to the Financial and Operating Results section of this MD&A for detailed discussions of changes in the fourth 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") of Raging River have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings* ("NI 52-109") of the Canadian Securities Administrators. The CEO and CFO have evaluated the disclosure controls and procedures as at December 31, 2015 and have concluded that they were effective as at such date.

Internal Controls over Financial Reporting

The CEO and the CFO of Raging River have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR") as defined in NI 52-109. The control framework Raging River's officers used to design the Company's ICFR is the Internal Control - Integrated Framework (2013) ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway

Commission ("COSO"). The CEO and CFO have concluded that the Company's internal controls over financial reporting were effective as of December 31, 2015. There have been no changes in the Company's internal controls over financial reporting during the period from January 1, 2015 to December 31, 2015 that have materially affected, or are reasonably likely to materially affect the Company's 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 National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*. 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, 2015 audited annual 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, 2017, 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.

IFRS 16 Leases, which replaces IAS 17 Leases was issued in January 2016. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. Management is currently assessing the potential impact of the adoption of IFRS 16 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, Azimuth Capital Management
Calgary, Alberta

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

Officers

NEIL ROSZELL, P. Eng.
President & CEO

BRUCE BEYNON
Executive Vice President

JERRY SAPIEHA, CA
Vice President Finance & CFO

JASON JASKELA
Vice President Production & COO

TERRY DANKU
Vice President Business Development

SCOTT RIDEOUT
Vice President Land

JESSE BARLOW
Vice President Engineering

TED BROWN (Corporate Secretary)
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