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 3, 2017 and should be read in conjunction with the unaudited interim financial statements for the three and six months ended June 30, 2017 and the audited financial statements for the year ended December 31, 2016 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, except when noted otherwise.

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 2017 capital budget including expected capital expenditures, expectations that the Company will have adequate liquidity to fund operations and capital expenditures and expected sources of financing for any expansion of the capital program or any significant acquisition that may be undertaken by the Company. 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. 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,	
	2017	2016	2017	2016
	(thousands of dollars)		*(thousands of dollars)*	
Cash flow from operating activities	61,543	35,638	140,803	64,809
Changes in non – cash working capital	3,422	8,361	(3,086)	9,092
Funds flow from operations	64,965	43,999	137,717	73,901

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: the total amount of current and long-term debt the Company has; the amount of revenues received on a per unit of production basis after the royalties, operating and transportation costs; and 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, respectively. 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

Barrels of Oil Equivalent

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 crude 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 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 is 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 2017 HIGHLIGHTS

- Achieved quarterly average production of 22,015 boe/d (91% oil), an increase of 38% over the comparable period in 2016. This represents a 35% production per share increase from the comparable period of 2016.

- The Company's capital expenditures were $68.6 million inclusive of $9 million on land and $59.6 million of development capital resulting in the drilling of 60.6 net Viking horizontal wells at a 97% success rate.

- Achieved funds flow from operations ("FFO") of $65 million ($0.28/share basic), an increase of 48% from the second quarter of 2016.

- Generated second quarter net earnings of $18.6 million, an increase of 250% from the second quarter 2016.

- The Company generated field operating netbacks of $35.13/boe and funds flow netbacks of $32.42/boe.

- Continued diligent cost control with top decile general and administrative costs of $1.05/boe, a reduction of 13% from the comparable period in 2016.

- Maintained balance sheet strength with second quarter exit net debt of $253.1 million representing 1.0 times debt to the second quarter annualized FFO.

Subsequent to June 30, 2017

- Effective July 31, 2017, the lenders have increased the Company's credit facilities to $500 million comprised of a $50 million non-syndicated operating facility and a $450 million syndicated extendible revolving facility, on similar terms and conditions to the Company's pre-existing credit facilities.

Petroleum and Natural Gas Operations

Production and Pricing

	Three months ended June 30, 2017	2016	Percent Change	Six months ended June 30, 2017	2016	Percent Change
Operating: (6:1 boe conversion)						
Average daily production						
Light oil and liquids (bbls/d)	18,795	14,603	29	19,134	14,818	29
Heavy oil (bbls/d)	1,189	171	595	1,303	163	699
Natural gas (mcf/d)	12,185	7,368	65	11,676	7,634	53
Barrels of oil equivalent (boe/d)	22,015	16,002	38	22,383	16,253	38
Raging River average sales price						
Light oil and liquids ($/bbl)	57.35	49.68	15	58.27	42.67	37
Heavy oil ($/bbl)	45.75	31.10	47	44.99	24.81	81
Natural gas ($/mcf)	2.66	1.10	142	2.65	1.51	75
Barrel of oil equivalent ($/boe)	52.90	46.37	14	53.81	39.86	35
Average Benchmark Prices						
Crude Oil - WTI (US$/bbl)	48.27	45.59	6	50.09	39.52	27
Crude Oil – MSW (Cdn$/bbl)	61.84	54.70	13	62.85	47.70	32
Crude oil – WCS (Cdn$/bbl)	49.96	41.61	20	49.66	33.95	46
Natural gas – AECO (Cdn$/mcf)	2.79	1.42	96	2.74	1.62	69
Exchange rate (US$/Cdn$)	0.74	0.78	(5)	0.75	0.75	-

Revenues

	Three months ended June 30, 2017	2016	Percent Change	Six months ended June 30, 2017	2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Light oil and liquids revenue	97,963	66,225	48	201,585	114,958	75
Heavy oil revenue	4,950	484	923	10,613	734	1346
Natural gas revenue	2,952	740	299	5,603	2,097	167
Royalty revenue	117	79	48	198	120	65
	105,982	67,528	57	217,999	117,909	85

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 light crude oil are determined by the quality of the crude compared to the benchmark price for Mixed Sweet Blend (“MSW”) and Western Canadian Select (“WCS”) for heavy crude oil.

The Company's light crude oil price averaged $57.35/bbl in the second quarter of 2017, an increase of 15% from $49.68/bbl in the second quarter of 2016. The average quality adjustment to MSW pricing of $4.49/bbl narrowed in the second quarter of 2017 compared to $5.02/bbl in the second quarter of 2016. Raging River’s realized light oil is priced at Light Smiley in Kerrobert and discounted to MSW due to quality adjustments, net of fees including pipeline tariffs and location differentials. The decrease in the differential to MSW in 2017 compared to 2016, primarily relates to an increase in demand of light crude oil at Kerrobert.

The Company’s light crude oil price averaged $58.27/bbl in the first half of 2017, a significant increase of 37% from the average price of $42.67/bbl received in the first half of 2016. Raging River’s average quality adjustment to MSW pricing decreased in the first half of 2017 to $4.58/bbl from $5.03/bbl in the first half of 2016. The increase in the realized light oil crude price in the first half of 2017 correlates to the increase in the MSW benchmark price.

The Company's heavy crude oil price averaged $45.75/bbl for the second quarter of 2017, a significant increase of 47% from $31.10/bbl in the second quarter of 2016. In the first half of 2017, the heavy crude oil price averaged $44.99/bbl, a significant increase of 81% from $24.81/bbl in the first half of 2016. The average quality adjustment to WCS narrowed in both the three and six months ended June 30, 2017, due to the acquisition of heavy oil properties with a higher API, acquired through the corporate acquisition that closed in July 2016. The increase in the heavy crude oil price in the first half of 2017 from the comparable period of 2016, is consistent with the increase in the WCS benchmark price.

The AECO natural gas price increased in 2017 due to cold winter weather early in the year that triggered large storage withdrawals, resulting in an upward pressure on natural gas pricing. In the second quarter of 2017, natural gas levels remained closer to seasonal averages with steady supply and demand. The upward pressure on natural gas pricing resulted in an increase in the natural gas price realized by the Company. Raging River’s realized natural gas price for the three and six months ended June 30, 2017 was $2.66 per mcf and $2.65 per mcf respectively, compared to $1.10 per mcf and $1.51 per mcf for the same periods in 2016.

Drilling and Production

During the first half of 2017, the Company drilled a total of 168 (160.1 net) wells resulting in 160 (152.1 net) crude oil wells, 5 (5.0 net) service wells and 3 (3.0 net) dry and abandoned wells for a success rate of 98%.

Production	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15
Light oil and liquids (bbls/d)	18,795	19,476	17,058	15,643	14,603	15,034	14,021	12,805	12,664
Heavy oil (bbls/d)	1,189	1,419	1,780	1,738	171	154	173	204	192
Natural gas (mcf/d)	12,185	11,161	9,652	7,385	7,368	7,900	3,461	2,454	2,947
Total (boe/d)	22,015	22,755	20,447	18,612	16,002	16,505	14,771	13,418	13,347
% increase over prior quarter	(3%)	11%	10%	16%	(3%)	12%	10%	1%	-
Production per 1 million shares	95.2	98.5	88.5	80.8	70.7	76.2	72.8	67.2	67.4
Per share % increase (decrease) over prior quarter	(3%)	11%	10%	14%	(7%)	5%	8%	-	(4%)

The Company’s production for the second quarter of 2017 increased to 22,015 boe/d from 16,002 boe/d in the second quarter of 2016, an increase of 38%. Quarter over quarter, production in the second quarter of 2017 decreased 3% to 22,015 boe/d from 22,755 boe/d in the first quarter of 2017 primarily due to normal spring break-up conditions. The year over year increase was primarily attributable to a successful drilling program in 2017 and 2016 combined with strategic property and corporate acquisitions.

Petroleum and natural gas revenue in the three months ended June 30, 2017 was $106 million as compared to $67.5 million in the corresponding period of 2016. This increase was the result of a 38% increase in production volumes combined with a 14% increase in commodity pricing.

Petroleum and natural gas revenues in the six months ended June 30, 2017 was $218 million, as compared to $117.9 million in the corresponding period of 2016, representing an increase of $100.1 million or 85%. The increase is attributable to a 38% increase in production volumes combined with a 35% increase in commodity pricing.

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 3, 2017, the Company has the following price contracts in place by quarter:

2017

Q3					
Crude oil	Differential	Jul 2017 – Sept 2017	2,000 bbls/d	Cdn $4.47/bbl	WTI/Edm
Crude oil	Differential	Jul 2017 – Sept 2017	6,000 bbls/d	US$2.97/bbl	WTI/Edm
Natural gas	Fixed	Jul 2017 – Sept 2017	2,500 GJs/d	Cdn $3.06/GJ	AECO
Q4					
Crude oil	Differential	Oct 2017 – Dec 2017	2,000 bbls/d	Cdn $4.47/bbl	WTI/Edm
Crude oil	Differential	Oct 2017 – Dec 2017	6,000 bbls/d	US$2.97/bbl	WTI/Edm
Natural gas	Fixed	Oct 2017 – Dec 2017	2,500 GJs/d	Cdn $3.06/GJ	AECO

Realized & Unrealized Gain/Loss on Commodity Contracts

The realized gain/loss represents the commodity contracts settled during the three and six months ended June 30, 2017. 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 Company's natural gas commodity contracts are referenced to the AECO daily and monthly index.

For the three months ended June 30, 2017, the Company realized a loss of $741 thousand (three months ended June 30, 2016 - realized gains of $154 thousand). The Company realized losses on crude oil differential commodity contracts that was partially offset by gains realized on fixed gas commodity contracts. The Company had crude oil commodity contracts to fix the differential between the WTI and Edmonton SW - Blended price at Cdn$4.12/bbl and US$2.98/bbl. The actual differentials were Cdn$3.00/bbl and US$2.07/bbl, resulting in a realized loss. The narrowing of the differentials in the quarter is attributable to the Syncrude fire and subsequent maintenance that removed significant production from the market, causing a crude shortage therefore driving up the price for Canadian light oil. The Company had natural gas commodity contracts to fix the AECO index price at an average of Cdn$3.06/GJ. The AECO settlement price averaged Cdn$2.63/GJ, resulting in a realized gain in the period.

In the six months ended June 30, 2017, the Company recorded a $468 thousand loss (six months ended June 30, 2016 - realized gain of $358 thousand). The Company realized gains on natural gas commodity contracts due to the fixed AECO contracted price exceeding the AECO settlement price. This was offset by losses recognized on crude oil commodity contracts, as the differential between WTI and the Edmonton SW-blended price narrowed in the period.

As of June 30, 2017, the fair value of Raging River's outstanding commodity contracts is an unrealized asset of $401 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, 2017, 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, 2017. The unrealized gain of $777 thousand for the six months ended June 30, 2017, represents the fair value change of the underlying commodity contracts to be settled in the future. In comparison, an unrealized loss of $345 thousand was recorded for the six months ended June 30, 2016.

In the second quarter of 2017, the Company had unrealized gains of $1.9 million compared to unrealized losses of $602 thousand in the second quarter of 2016.

Royalties

	Three months ended June 30, 2017	Three months ended June 30, 2016	Percent Change	Six months ended June 30, 2017	Six months ended June 30, 2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Crown	2,237	1,265	77	4,705	2,285	106
Saskatchewan resource surcharge	1,698	1,229	38	3,419	2,186	56
Freehold and GORR	6,184	4,112	50	12,680	7,044	80
	10,119	6,606	53	20,804	11,515	81
Percent of total revenue	9.5%	9.8%	(3)	9.5%	9.8%	(3)
Per boe ($)	5.05	4.54	11	5.14	3.89	32

Royalty expenses consist of royalties paid to provincial governments, freehold landowners, overriding royalty owners and the Saskatchewan resource surcharge. Royalties increased to $10.1 million in the three months ended June 30, 2017, from $6.6 million in the comparable period of 2016, primarily due to a combination of a 14% increase in commodity pricing and a 38% increase in production volumes. The Company's average royalty rate of 9.5% in the three months ended June 30, 2017, was consistent with the royalty rate in the comparable period in 2016 of 9.8%. On a boe basis, the increase in the quarter is consistent with the increase in the commodity prices.

During the six months ended June 30, 2017, royalties increased 81% to $20.8 million from $11.5 million in the comparable period. The increase is again primarily a result of a 35% increase in commodity pricing and 38% increase in production volumes. The Company's average royalty rate was 9.5% in the first half of 2017 compared to 9.8% in 2016.

Operating Expenses

	Three months ended June 30, 2017	Three months ended June 30, 2016	Percent Change	Six months ended June 30, 2017	Six months ended June 30, 2016	Percent Change
Total operating costs ($000's)	22,650	13,074	73	44,158	26,523	67
Percent of total revenue	21.3%	19.4%	10	20.2%	22.5%	(10)
Per boe ($)	11.31	8.98	26	10.90	8.97	22

During the three months ended June 30, 2017, operating expenses increased 73% to $22.7 million compared to $13.1 million in the same period of 2016. During the six months ended June 30, 2017, operating expenses increased 67% to $44.2 million compared to $26.5 million in 2016. The increase in total operating costs is primarily due to the increase in production volumes in both the three and six months ended June 30, 2017.

Operating costs averaged $11.31/boe in the second quarter of 2017 and $10.90/boe in the year to date. This represents an increase of 26% or $2.33/boe from $8.98/boe in the second quarter of 2016 and an increase of 22% or $1.93/boe from $8.97/boe in the first half of 2016. Operating costs per boe increased in both the three and six months ended June 30, 2017, primarily due to the heavy oil properties acquired from the corporate acquisition that closed in July 2016, which carry higher operating costs than Raging River's historical average. When combined with ongoing wellsite maintenance expenditures, increased service and product costs and numerous production optimization workovers, operating costs have increased in 2017.

Transportation Expenses

	Three months ended June 30, 2017	2016	Percent Change	Six months ended June 30, 2017	2016	Percent Change
Total transportation costs ($000's)	2,824	2,025	39	5,793	4,082	42
Percent of total revenue	2.7%	3.0%	(10)	2.7%	3.5%	(23)
Per boe ($)	1.41	1.39	1	1.43	1.38	4

Transportation expenses relate to the cost of transporting liquids and natural gas and hauling crude oil to the point of sale. Transportation costs increased to $2.8 million in the three months ended June 30, 2017, from $2 million in the comparable period of 2016. During the six months ended June 30, 2017, transportation costs increased 42% to $5.8 million from $4.1 million in the comparable period. The increase in transportation expenses is primarily a result of a 38% increase in production volumes.

Transportation costs averaged $1.41/boe in the second quarter of 2017 and $1.43/boe in the year to date. Transportation costs per boe were consistent with the comparable period in both the three and six months period ended June 30, 2016.

General and Administrative ("G&A") Expenses

	Three months ended June 30, 2017	2016	Percent Change	Six months ended June 30, 2017	2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
General and administrative	4,034	2,630	53	7,601	5,482	39
Overhead recoveries	(913)	(190)	381	(1,541)	(505)	205
Capitalized G&A	(1,022)	(692)	48	(1,865)	(1,339)	39
	2,099	1,748	20	4,195	3,638	15
Percent of total revenue	2.0%	2.6%	(23)	1.9%	3.1%	(39)
Per boe ($)	1.05	1.20	(13)	1.04	1.23	(15)

The Company incurred gross G&A costs of $4 million and $7.6 million in the three and six months ended June 30, 2017, respectively, an increase of 53% from $2.6 million and 39% from $5.5 million in the comparable periods of 2016. Increased G&A expenses before recoveries and capitalization were mainly a result of employee related costs, office rent and software fees, all of which are driven by the capital growth of the Company and its operations. Higher salary costs were driven by increased personnel including technical, operations and administrative staff. Capitalized G&A and overhead recoveries increased in both the three and six months ended June 30, 2017, due to a substantial increase in exploration and development expenditures.

Net general and administration expenses for the three and six months ended June 30, 2017, were $2.1 million or $1.05/boe and $4.2 million or $1.04/boe, respectively, compared to $1.7 million or $1.20/boe and $3.6 million or $1.23/boe in the corresponding periods of 2016. The decrease in net G&A per boe from the comparable period is a result of continued G&A efficiencies achieved combined with higher production levels.

Financial Charges

	Three months ended June 30,		Percent Change	Six months ended June 30,		Percent Change
	2017	2016		2017	2016	
Financial charges ($000's)	2,293	676	239	4,321	1,903	127
Percent of total revenue	2.2%	1.0%	120	2.0%	1.6%	25
Per boe ($)	1.14	0.46	148	1.07	0.64	67

Financial charges for the three and six months ended June 30, 2017, were $2.3 million and $4.3 million compared to $676 thousand and $1.9 million in the corresponding periods of 2016. Interest on bank debt increased in the second quarter of 2017 as compared to the second quarter of 2016, due to carrying significantly higher average debt levels of $183 million in 2017 compared to $58 million in 2016. Debt levels increased in the quarter to fund the significant 2017 capital expenditure program and increased operations. As at June 30, 2017, the Company had drawn $202.8 million against the available credit facilities of $400 million.

Subsequent to June 30, 2017, and effective July 31, 2017, the syndicate of lenders underwriting the Company's credit facilities confirmed the increase in the Company's borrowing facility to $500 million from $400 million. The $500 million credit facilities are comprised of a $50 million non-syndicated operating facility and a $450 million syndicated extendible revolving facility, on similar terms to the Company's pre-existing credit facilities. The next review of the borrowing base will be in October 2017.

Stock-based Compensation

	Three months ended June 30,		Percent Change	Six months ended June 30,		Percent Change
	2017	2016		2017	2016	
	(thousands of dollars)			*(thousands of dollars)*		
Stock options	1,518	1,880	(19)	3,412	4,077	(16)
Share based awards	825	547	51	1,834	547	235
Capitalized stock based compensation	(487)	(506)	(4)	(1,098)	(1,049)	5
Stock based compensation expense	1,856	1,921	(3)	4,148	3,575	16
Percent of total revenue	1.8%	2.8%	(36)	1.9%	3.0%	(37)
Per boe ($)	0.93	1.32	(30)	1.02	1.21	(16)

Stock based compensation expense in the three and six months ended June 30, 2017, was $1.9 million and $4.1 million, respectively, compared to $1.9 million and $3.6 million in the corresponding periods of 2016. Stock based compensation expense relating to stock options decreased in the three and six months ended June 30, 2017, as the fair value of new grants is lower than in previous periods. Stock based compensation relating to share based awards increased in both the three and six month periods ended due to additional amortization of share based awards from new grants throughout 2016 and 2017.

Stock options

During the second quarter of 2016, the shareholders of the Company approved a new stock option plan ("New Option Plan"). Stock options that have been granted under the New Option Plan 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 relating to options is accounted for using the fair value method of accounting. The expense associated with stock options is driven by the timing and valuation of stock option grants.

As at June 30, 2017, the Company had a total of 10.4 million stock options outstanding with a weighted average fair value of $2.49 per stock option.

Share based awards

During the second quarter of 2016, the shareholders of the Company approved the awards plan consisting of restricted share units ("RSUs") and performance share units ("PSUs") whereby units may be granted to officers, employees and consultants of the Company. The maximum number of common shares issuable under the plan shall not at any time exceed the lessor of: (i) 5% of the total common shares less the aggregate number reserved for issuance pursuant under the new stock option plan and (ii) 6.5% of the total common shares outstanding less the aggregate number of common shares reserved for issuance pursuant to the old stock options. Currently one third of the RSUs will vest on each of the first, second and third anniversaries of the date of grant. PSUs will vest three years after the grant date, unless otherwise determined by the board and are adjusted based on a payout multiplier. The payout multiplier ranges from 0 to 2 and is based on corporate performance measures determined by the board of directors.

RSUs and PSUs are measured at fair value using the closing trading price on the date of grant. The resulting stock-based compensation expense is recognized over the vesting period with the corresponding increase to contributed surplus. Upon the settlement of the RSUs and PSUs, the associated amount in contributed surplus is recorded as an increase to share capital. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of awards that vest.

As at June 30, 2017, the Company had 423,700 RSUs and 588,840 PSUs outstanding.

On April 4, 2016, the board of directors of the Company approved the adoption of the Deferred Share Units ("DSUs") plan. DSUs are granted to non-employee directors. Each DSU vests on the date of grant, however, settlement of the DSU occurs when the individual ceases to be a director of the Company. DSUs are to be settled in cash or by payment in common shares acquired through the facilities of the Toronto Stock Exchange ("TSX"). The directors may also elect to receive all of their annual cash compensation in the form of DSUs provided that such election must be made on December 1st of the preceding calendar year (or within certain prescribed time frame if an individual becomes a director after the commencement of a calendar year) and after such date the election will be irrevocable for such year.

DSUs are measured at fair value using the closing trading price on the date of grant.

As at June 30, 2017, the Company had 112,766 DSUs outstanding.

Depletion, Depreciation and Accretion

	Three months ended June 30, 2017	2016	Percent Change	Six months ended June 30, 2017	2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Depletion and depreciation	43,875	32,494	35	88,029	65,458	34
Exploration and evaluation lease expiries	66	502	(87)	3,151	2,699	17
Accretion	599	364	65	1,171	713	64
	44,540	33,360	34	92,351	68,870	34
Percent of total revenue	42.0%	49.4%	(15)	42.4%	58.4%	(27)
Per boe ($) – Depletion and depreciation	21.90	22.31	(2)	21.73	22.13	(2)
Per boe ($) – Exploration and evaluation lease expires	0.03	0.34	(91)	0.78	0.91	(14)
Per boe ($) – Accretion	0.30	0.25	20	0.29	0.24	21

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 for the three and six months ended June 30, 2017, was $43.9 million and $88.0 million compared to $32.5 million and $65.5 million in the corresponding periods of 2016. The increase in depletion expense is a result of a 38% increase in production volumes, combined with a large increase to the capital base from capital expenditures from an intensive drilling program and acquisitions that closed throughout 2016. Depletion per boe remained consistent in the three and six months ended June 30, 2017 compared to the same periods in 2016 as capital additions were offset by reserve additions.

During the six months ended June 30, 2017, $3.2 million of costs associated with expired mineral leases were recognized as exploration and evaluation expense in the statement of comprehensive earnings. In comparison, $2.7 million of lease expiries were recorded in the first half of 2016. Saskatchewan crown land leases come up for renewal annually in the first quarter of the year.

Accretion increased in the second quarter of 2017 to $599 thousand from $364 thousand in the comparable quarter of 2016. This increase is primarily due to the increase in asset retirement obligations from drilling and acquisition activities. Accretion represents the time value of the asset retirement obligations 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.

Asset Retirement Obligations

As at June 30, 2017, the asset retirement obligations of the Company were $110.5 million, an increase of $12.7 million from the asset retirement obligations of $97.8 million as at December 31, 2016. This increase is related to the capital exploration and development program in the first half of 2017 combined with an upward revision to the estimate. The revision to estimated asset retirement obligations of $5.1 million was due to discounting future cost estimates at a lower rate than in prior periods.

Income Taxes

During the three and six months ended June 30, 2017, the Company recorded a deferred income tax provision of $2.2 million and $8.6 million respectively, compared to $2.9 million and $3.8 million in the corresponding periods of 2016. The Company's effective tax provision rate is 22% due to the reduction in the Saskatchewan corporate income tax rate.

Raging River was not required to pay income taxes in the current period as the Company had sufficient income tax deductions available to shelter taxable income. The Company recorded a current tax recovery of $0.5 million in the three months ended June 30, 2016 and $3.4 million in the year to date 2016.

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, 2017, Raging River recorded funds flow from operations of $137.7 million and net income of $34 million. This is a significant increase from the 2016 second quarter results with funds flow from operations of $73.9 million and a net loss of $2.5 million, due primarily to the significant increase in commodity pricing and production volumes that was partially offset by higher operating and transportation costs.

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

	Three months ended June 30, 2017	Three months ended June 30, 2016	Percent Change	Six months ended June 30, 2017	Six months ended June 30, 2016	Percent Change
	($/boe)			($/boe)		
Petroleum and natural gas revenue	52.90	46.37	14	53.81	39.86	35
Realized gain (loss) on commodity contracts	(0.37)	0.11	(436)	(0.12)	0.12	(200)
Royalties	(5.05)	(4.54)	11	(5.14)	(3.89)	32
Net revenue	47.48	41.94	13	48.55	36.09	35
Operating expenses	(11.31)	(8.98)	26	(10.90)	(8.97)	22
Transportation expenses	(1.41)	(1.39)	1	(1.43)	(1.38)	4
Operating netback[(1)]	34.76	31.57	10	36.22	25.74	41
General and administrative expenses	(1.05)	(1.20)	(13)	(1.04)	(1.23)	(15)
Financial charges	(1.14)	(0.46)	148	(1.07)	(0.64)	67
Asset retirement expenditures	(0.15)	(0.04)	275	(0.13)	(0.04)	225
Current tax recovery	-	0.34	(100)	-	1.15	(100)
Funds flow from operations[(1)]	32.42	30.21	7	33.98	24.98	36
Unrealized gain (loss) on financial instruments	0.97	(0.41)	(337)	0.19	(0.12)	(258)
Stock-based compensation expense	(0.93)	(1.32)	(30)	(1.02)	(1.21)	(16)
Asset retirement expenditures	0.15	0.04	275	0.13	0.04	225
Depletion and depreciation expense	(21.90)	(22.31)	(2)	(21.73)	(22.13)	(2)
Exploration and evaluation lease expiries	(0.03)	(0.34)	(91)	(0.78)	(0.91)	(14)
Accretion expense	(0.30)	(0.25)	20	(0.29)	(0.24)	21
Earnings before deferred income taxes	10.38	5.62	85	10.48	0.41	2456
Deferred income tax expense	(1.10)	(1.96)	(44)	(2.12)	(1.27)	67
Net earnings (loss)	9.28	3.66	154	8.36	(0.86)	(1072)

(1) Non-GAAP measures. See Non-GAAP measures advisory.

Capital Expenditures

Total capital expenditures for the three and six months ended June 30, 2017, were $68.6 million and $181.3 million respectively, compared to $63.7 million and $101.1 million for the same periods in 2016. The expenditures are detailed below:

	Three months ended June 30, 2017	Three months ended June 30, 2016	Percent Change	Six months ended June 30, 2017	Six months ended June 30, 2016	Percent Change
	(thousands of dollars)			*(thousands of dollars)*		
Land	9,027	2,041	342	15,213	2,578	490
Geological and geophysical	26	23	13	27	26	4
Drilling and completions	38,959	28,420	37	108,122	55,976	93
Facilities and equipping	20,619	8,098	155	57,948	17,346	234
Other	9	20	(55)	13	56	(77)
Exploration and development	68,640	38,602	78	181,323	75,982	14
Property acquisitions	-	25,125	(100)	-	25,125	(100)
Total invested capital	68,640	63,727	8	181,323	101,107	79

In the first half of 2017, Raging River drilled a total of 168 (160.1) wells. This included 160 (152.1 net) crude oil wells, 5 (5.0 net) service well and 3 (3.0 net) dry and abandoned wells for an overall success rate of 98%. In the second quarter of 2017, Raging River drilled a total of 64 (60.6 net) crude oil wells with a success rate of 97%. By comparison, the Company drilled a total of 40 (39.9 net) wells in the second quarter of 2016 and 98 (97.4 net) wells in the six months ended June 30, 2016.

In the three months ended June 30, 2017, the Company invested a total of $68.6 million on capital expenditures including $59.6 million on drilling, completing, and equipping activities, and $9 million on land and geological and geophysical costs.

During the first half of 2017, the Company spent $181.3 million on capital expenditures including $166.1 million on drilling, completions and production facilities, and $15.2 million on land and geological and geophysical costs.

The Company is maintaining a 2017 capital expenditure budget of $340 million which includes $270 million of exploration and development expenditures, $50 million to waterflood and gas conservation and remaining $20 million to land, seismic and maintenance capital. The capital budget is expected to be funded from a combination of anticipated 2017 cash flow combined with the Company’s increased credit facilities of $500 million.

Drilling Activity

The following table summarizes our drilling results:

	Three months ended June 30, 2017 Gross	2017 Net	2016 Gross	2016 Net	Six months ended June 30, 2017 Gross	2017 Net	2016 Gross	2016 Net
Crude oil	62	58.6	39	38.9	160	152.1	96	95.4
Natural gas	-	-	-	-	-	-	-	-
Service/Injection	-	-	-	-	5	5.0	1	1.0
Dry and abandoned	2	2.0	1	1.0	3	3.0	1	1.0
Total	64	60.6	40	39.9	168	160.1	98	97.4
Success (1)	97%	97%	98%	98%	98%	98%	99%	99%

(1) Does not include service well.

Liquidity and Capital Resources

At June 30, 2017, the Company had net debt of $253.1 million compared to net debt of $209.5 million at December 31, 2016. For the six months ended June 30, 2017, funds flow from operations of $137.7 million less capital expenditures of $181.3 million resulted in the ending net debt of $253.1 million. The Company expects to have adequate liquidity to fund the 2017 capital expenditure budget of $340 million through a combination of funds flow from operations and the increase to the credit facilities of $500 million. 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,	
	2017	2016
($ thousands)		
Capital Resources		
Bank debt available	400,000	300,000
Net debt	(253,117)	(63,101)
Total capital resources available	146,883	236,899
Subsequent increase to credit facilities	100,000	-
	246,883	236,899

Changes to share capital in 2017 were the following:

During the six months ended June 30, 2017, 60.3 thousand common shares were released from treasury to settle the vesting of 60.3 thousand restricted and performance share units.

During the six months ended June 30, 2017, 145 thousand stock options were exercised for 35 thousand common shares on a cash-less basis and 5 thousand stock options were exercised for 5 thousand common shares for proceeds of $32 thousand.

Common share information

CAPITALIZATION

Share Capital

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Weighted average outstanding common shares (1)				
-Basic	231,178	226,231	231,165	221,362
-Diluted	231,335	227,167	231,402	221,362
Outstanding securities at June 30, 2017				
-Common shares				231,242,893
-Stock options – weighted average exercise price of $9.23				10,383,625
-Restricted share units				423,700
-Performance share units				588,840
-Deferred share units				112,766

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options, RSUs, and PSUs. Under this method, only “in-the-money” dilutive instruments impact the calculation of diluted profit per common share.

Total Market Capitalization

The Company's market capitalization at June 30, 2017 was approximately $1.9 billion.

	June 30, 2017
Common shares outstanding	231,242,893
Share price [(1)]	$8.09
Total market capitalization	$1,870,755,004

(1) Represents the closing price traded on the TSX on June 30, 2017.

As at August 3, 2017 the Company had 231,248,245 common shares outstanding.

	August 3, 2017
Outstanding securities at August 3, 2017	
-Common shares	231,248,245
-Stock options – weighted average exercise price of $9.24	10,262,624
-Restricted share units	423,700
-Performance share units	588,840
-Deferred share units	112,766

Subsequent Event

Effective July 31, 2017, the lenders have increased the Company's credit facilities to $500 million comprised of a $50 million non-syndicated operating facility and a $450 million syndicated extendible revolving facility, with similar terms and conditions as referenced in note 7 in the unaudited interim financial statements for the three and six months ended June 30, 2017. The next review of the borrowing base will be in October 2017.

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. As at June 30, 2017, the Company was committed to the future minimum payments as follows:

Payments due by Period ($ thousands)	Less than 1 Year	1 to 3 Years	4 to 5 Years	After 5 Years	Total
Office lease	953	1,132	-	-	2,085
Bank debt	-	202,842	-	-	202,842
Processing	4,293	3,910	-	-	8,203
Transportation	2,898	5,007	-	-	7,905
Total contractual obligations and commitments	8,144	211,891	-	-	221,035

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 2017.

Summary of Quarterly Results

	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15
Financial *(thousands of dollars except share data)*								
Petroleum and natural gas revenue	105,982	112,017	98,479	80,632	67,528	50,382	62,943	63,518
Funds flow from operations (1)	64,965	72,752	64,561	49,726	43,999	29,904	40,708	43,630
Per share - basic	0.28	0.31	0.28	0.22	0.19	0.14	0.20	0.22
- diluted	0.28	0.31	0.28	0.22	0.19	0.14	0.20	0.22
Net earnings (loss)	18,595	15,343	18,986	6,758	5,320	(7,852)	5,120	10,893
Per share - basic	0.08	0.07	0.08	0.03	0.02	(0.04)	0.03	0.05
- diluted	0.08	0.07	0.08	0.03	0.02	(0.04)	0.03	0.05
Capital expenditures, net	68,640	112,685	134,917	120,179	63,727	37,380	76,284	49,760
Net debt (4)(6)	253,117	249,475	209,543	140,187	63,101	44,564	139,943	103,659
Shareholders' equity	938,337	917,366	899,120	877,442	826,775	817,839	719,213	616,834
Weighted average shares *(thousands)*								
Basic	231,178	231,152	231,114	230,227	226,231	216,493	202,977	199,576
Diluted	231,335	231,501	232,048	231,154	227,167	216,493	203,897	201,648
Shares outstanding, end of period *(thousands)*								
Basic	231,243	231,156	231,142	231,039	226,600	226,014	213,421	200,319
Diluted	232,979	236,603	239,961	240,434	235,878	232,741	216,417	204,653
Operating *(6:1 boe conversion)*								
Average daily production								
Light oil and NGLs *(bbls/d)*	18,795	19,476	17,058	15,643	14,603	15,034	14,021	12,805
Heavy oil *(bbls/d)*	1,189	1,419	1,780	1,738	171	154	173	204
Natural gas *(mcf/d)*	12,185	11,161	9,652	7,385	7,368	7,900	3,461	2,454
Barrels of oil equivalent (2) *(boe/d)*	22,015	22,755	20,447	18,612	16,002	16,505	14,771	13,418
Average selling prices(4)								
Light oil and NGLs *(bbls/d)*	57.35	59.16	56.56	50.78	49.68	35.47	47.64	52.54
Heavy oil *(bbls/d)*	45.75	44.35	43.51	37.66	31.10	17.84	31.72	39.38
Natural gas *($/mcf)*	2.66	2.64	2.91	2.06	1.10	1.89	2.31	2.82
Barrels of oil equivalent (2) *($/boe)*	52.90	54.70	52.35	47.09	46.37	33.54	46.32	51.45
Netbacks ($/boe)								
Operating								
Petroleum and natural gas revenue(4)	52.90	54.70	52.35	47.09	46.37	33.54	46.32	51.45
Realized gain (loss) on commodity contracts	(0.37)	0.13	(0.15)	(0.05)	0.11	0.14	0.89	0.80
Royalties	(5.05)	(5.22)	(4.94)	(4.55)	(4.54)	(3.27)	(4.72)	(4.52)
Operating expenses	(11.31)	(10.50)	(10.79)	(10.15)	(8.98)	(8.95)	(8.92)	(9.14)
Transportation expenses	(1.41)	(1.45)	(1.42)	(1.46)	(1.39)	(1.37)	(1.36)	(1.37)
Operating netback *($/boe)*(5)(6)	34.76	37.66	35.05	30.88	31.57	20.09	32.21	37.22
General and administrative	(1.05)	(1.02)	(1.00)	(1.15)	(1.20)	(1.26)	(1.35)	(1.18)
Financial charges	(1.14)	(0.99)	(0.82)	(0.63)	(0.46)	(0.82)	(0.84)	(0.71)
Asset retirement obligation	(0.15)	(0.12)	(0.12)	(0.05)	(0.04)	(0.03)	(0.06)	-
Current tax recovery	-	-	1.22	-	0.34	1.93	-	-
Funds flow netback(3)(6) *($/boe)*	32.42	35.53	34.33	29.05	30.21	19.91	29.96	35.33

(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 netbacks are calculated as revenue (after realized gain (loss) on commodity contracts) less royalties, operating expenses and transportation expenses.
(6) See "Non-GAAP Measures"

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 2017, the Company has maintained an active capital expenditure

program combined with strategic property and corporate acquisitions. This has resulted in a substantial increase on a quarter over quarter basis in the Company's production. Revenue, funds flow from operations and net earnings declined in 2015 and into 2016 due to the significant decline of global crude oil prices. As oil prices started to recover in late 2016, the Company's revenue, funds flow from operations and net earnings increased. In the first quarter of 2017, the Company reported its highest average realized price, revenue and funds flow from operations in eight consecutive quarters. Crude oil prices decreased in the second quarter of 2017 resulting in a slight decline of funds flow from operations, revenue and net earnings in period from the first quarter of 2017.

Please refer to the Financial and Operating Results section of this MD&A for detailed discussions of changes in the second quarter of 2017.

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 – *Certification of Disclosure in Issuers' Annual and Interim Filings* of the Canadian Securities Administrators ("NI 52-109"), 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 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) published by The Committee of Sponsoring Organizations of the Treadway Commission. The CEO and

CFO have concluded that the Company’s internal controls over financial reporting were effective as of December 31, 2016. There have been no changes in the Company's internal controls over financial reporting during the period from April 1, 2017 to June 30, 2017 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 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, 2016 audited annual financial statements. 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 standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by Raging River on January 1, 2018. Management is in the process of reviewing its revenue streams and assessing the potential impact, if any, 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. The standard introduces a single lessee accounting model for leases 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 in the process of reviewing its lease contracts to assess the potential impact of the adoption of IFRS 16 on the Company's financial statements.

Corporate Information

Board of Directors

NEIL ROSZELL
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.
CEO & Executive Chairman

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President

JERRY SAPIEHA, CA
Vice President Finance & CFO

JASON JASKELA
Vice President Production & COO

JESSE BARLOW
Vice President Engineering

TERRY DANKU
Vice President Business Development

CHAD LUNDBERG
Vice President Operations

SCOTT RIDEOUT
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TED BROWN (Corporate Secretary)
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