February 21, 2018

RAGING RIVER EXPLORATION INC. ANNOUNCES PRELIMINARY 2017 RESULTS, 2017 YEAR END RESERVES AND OPERATIONS UPDATE

CALGARY, ALBERTA (February 21, 2018) Raging River Exploration Inc. ("**Raging River**" or the "**Company**") (TSX:RRX) is pleased to present the summary results of the independent reserves reports as prepared by Sproule Associates Ltd. ("Sproule") and GLJ Petroleum Consultants ("GLJ") as of December 31, 2017 (collectively the "Engineering Report").

During 2017, the Company invested $372.1 million (unaudited) consisting of $297.4 million of Viking development capital, $31.9 million of capital deployed into long term Viking waterflood initiatives as well as $42.8 million into the early stage land capture and initial evaluation of the emerging Duvernay light oil play. This invested capital resulted in estimated average 2017 annual production of 22,850 boe/d (92% oil) representing year over year production per share growth of 25% and replaced 252% of annual production on a proved plus probable basis.

2017 Operational and Financial Highlights

(References to 2017 operational and financial results are estimates only and have not been audited by our independent auditor. Raging River is expected to release its fourth quarter and year-end results after market close on March 5, 2018).

Key operational results during the fourth quarter and year ended December 31, 2017, are indicated below:

	Q4 2017 Est	2017 Est
Average production (boe/d)(1)	23,670	22,850
Royalties %	9.2%	9.4%
Operating expense ($/boe)	$11.02	$10.96
Transportation expense ($/boe)	$1.39	$1.42
Operating netback ($/boe) (2)	$41.13	$36.36
Capital expenditures ($ millions)	$74.6	$372.1
Net debt ($ millions)(2)	$299.6	$299.6

Notes:

(1) See "Barrels of Oil Equivalent"

(2) See "Non IFRS Measures"

Operations Update

Fourth quarter 2017 production averaged approximately 23,670 boe/d (93% oil), bringing average 2017 annual production to 22,850 boe/d (92% oil) representing year over year production per share growth of 25%.

The $372.1 million of capital resulted in 337.8 net Viking wells and 1 net Duvernay well. This included 363 (322.8 net) crude oil wells, 9 (9.0 net) injection wells and 7 (7.0 net) dry holes. In addition to the drilling capital, a total of $33.8 million was spent on land primarily in the east Duvernay shale basin.

For 2018, quarter to date, we have drilled approximately 72 net wells of the 111 net wells budgeted for the first quarter of 2018. Field conditions and access to services have been supportive and as a result, we anticipate completing all drilling and completion operations by early March. Total capital expenditures for the first quarter are expected to be approximately $110 million, allocated to 108 net Viking wells and 3 net Duvernay wells.

Duvernay Update

Our initial Duvernay light oil discovery well (4-11) in the Ferrybank area of central Alberta continues to produce at strong rates. The well has now been on production for approximately 100 days with a few intermittent shut-in periods for equipping and pump maintenance with cumulative oil production to date of 19,000 bbls. As anticipated, the well continues to produce at a very low gas oil ratio of 250-300 scf/bbl.

Continued geotechnical success has been observed throughout the first quarter. Our second well in the Ferrybank area (2-32) was successfully drilled to a 2 mile lateral length with geotechnical results exceeding our expectations for the area. Our third well in the Pembina (Pigeon Lake) area (14-36) was recently cored and is currently drilling its 1.5 mile lateral. This well has also confirmed our geotechnical expectations of this area with estimated net pay in excess of 20m. We anticipate drilling a fourth well in the Gilby area prior to break-up. The first four evaluation wells are targeted to provide an initial evaluation across our 250,000 net acres in the play.

GLJ evaluated the reserves associated with the discovery well at 4-11 and assigned proved producing and proved plus probable producing gross reserves of 181 and 229 mboe, respectively (96% oil). They also assigned 3.8 net undeveloped locations as a result of the success of 4-11 yielding total proved plus probable gross reserves assignments for Ferrybank of 1,151 mboe (95% oil).

2017 Corporate Reserves Highlights:

- Proven Developed Producing (“PDP”) reserves
  - Increased by 5% to 34.7 mmboe from 33 mmboe (93% oil).
  - Replaced production by 121%.
  - Excluding the capital associated with the Duvernay; finding and development (“F&D”) costs were $33.32 per boe resulting in a recycle ratio of 1.1 times

- Total Proven (“TP”) reserves
  - Increased 15% to 82 mmboe from 71.6 mmboe (94% oil).
  - Replaced production by 225%.
  - Excluding the capital associated with the Duvernay; F&D costs, including the change in FDC, were $26.69 per boe resulting in a recycle ratio of 1.4 times

- Proven plus Probable (“P+P”) reserves
  - Increased 14% to 106.7 mmboe from 94 mmboe (94% oil).
  - Replaced production by 252%.

- Excluding the capital associated with the Duvernay; F&D costs, including the change in FDC, were $23.28 per boe resulting in a recycle ratio of 1.6 times

- Based on the net present value of future net revenues discounted at 10% ("PV10") before taxes of our P+P reserves as presented in the Engineering Report, plus our internally estimated undeveloped land value of $237 million and net of estimated net debt of $299.6 million to the Company's net asset value as at December 31, 2017 equates to $9.16 per common share, up from $8.35 as at December 31, 2016.

2017 Independent Reserves Evaluation:

The following summarizes certain information contained in the Engineering Report. The Engineering Report was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Additional reserve information as required under NI 51-101 will be included in the Company's Annual Information Form which will be filed on SEDAR by the end of March 2018.

Corporate Reserves Information:

December 31, 2017

Reserves Category	Oil[1] Mbbl	Gas MMcf	Oil Equivalent MBOE	BTAX PV 10% ($000's)	Future Development Capital ($000's)	Net Undeveloped Wells Booked
Proved developed producing	32,467	13,480	34,713	869,270	-	-
Proved developed non-producing	7	423	78	536	-	-
Proven undeveloped	45,087	12,720	47,207	667,564	929,562	1,111
Total proven	77,561	26,622	81,998	1,537,370	929,562	1,111
Probable developed producing	8,983	3,525	9,570	226,553	-	-
Probable developed non-producing	997	105	1,015	20,442	-	-
Probable undeveloped	13,419	3,905	14,070	405,944	38,869	53
Total probable	23,399	7,536	24,655	652,940	38,869	53
Total proven plus probable	100,959	34,158	106,652	2,190,310	968,431	1,164

Notes:

1. *Oil" includes all light & heavy crude oil volumes, and natural gas liquids volumes. Of the total proven plus probable reserves volumes presented as "Oil" above, approximately 93% is light and medium crude oil, 6% is heavy crude oil and 1% is natural gas liquids volumes.*
2. *Reserves have been presented on gross basis which are the Company's total working interest share before the deduction of any royalties and without including any royalty interests of the Company.*
3. *Based on Sproule's December 31, 2017 escalated price forecast.*
4. *It should not be assumed that the present worth of estimated future net revenue presented in the tables above represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of Raging River's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.*
5. *All future net revenues are stated prior to provision for interest, general and administrative expenses and after deduction of royalties, operating costs, estimated well and facility abandonment and reclamation costs and estimated future capital expenditures. Future net revenues have been presented on a before tax basis.*
6. *Totals may not add due to rounding.*
7. *Pursuant to the COGE Handbook, reported reserves should target at least a 90 percent probability that the quantities actually recovered will be equal to or exceed the estimated proved reserves and that at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.*

Net Asset Value

December 31, 2017

	BTAX NPV 5%		BTAX NPV 10%	
	($000's)	$/share[6]	($000's)	$/share[6]
P+P NPV [1,2]	2,869,665	12.30	2,190,310	9.39
Undeveloped acreage [3]	236,801	1.02	236,801	1.02
Net debt [4]	(299,600)	(1.28)	(299,600)	(1.28)
Proceeds from stock options [5]	6,329	0.03	6,329	0.03
Net Asset Value (fully-diluted)	2,813,195	12.07	2,133,840	9.16

Notes:

1. *Evaluated by Sproule and GLJ as at December 31, 2017. Net present value of future net revenue does not represent fair market value of the reserves.*
2. *Net present values ("NPV") equals net present value of future net revenue before taxes based on Sproule's forecast prices and costs as of December 31, 2017.*
3. *Internally evaluated with an average value of $400 per acre for 592,003 undeveloped net acres.*
4. *Net debt as at December 31, 2017, including working capital deficit (unaudited).*
5. *Fully-diluted shares at December 31, 2017 total: including outstanding common shares of 231.3 million and 1.98 million stock options, restricted awards and performance awards that are in-the-money as at December 31, 2017*
6. *Per share figures based on fully-diluted shares outstanding as at December 31, 2017 – see note 5.*

Future Development Costs

The following is a summary of the estimated FDC required to bring P+P undeveloped reserves on production.

Future Development Capital Costs ($000s)

	Total Proved	Total Proved + Probable
2018	326,866	332,735
2019	340,677	357,097
2020	262,019	277,399
2021	-	1,200
Total undiscounted FDC	929,562	968,431
Total discounted FDC at 10% per year	817,143	849,666

Performance Measures[1]

	2017	2016	2015	2014	2013
Average crude oil price WTI US$/bbl	50.95	43.32	48.80	93.00	97.98
Capital ($000)	372,100	403,248	339,191	278,594	272,495
Production boe/d	22,850	17,900	13,715	10,755	5,665
Operating netback $/boe	36.36	29.76	35.51	64.51	60.07
Proved Producing					
Total Reserves mboe	34,713	32,991	24,530	19,103	12,004
Reserves additions mboe	10,062	15,013	10,433	11,024	9,599
FD&A $/boe[2]	36.98	26.86	32.51	25.27	28.39
Recycle Ratio[3]	0.98	1.1	1.09	2.55	2.12
Reserves Replacement[4]	121%	229%	208%	281%	464%
RLI (years)[5]	4.2	5.1	4.9	4.9	5.8
Proved Plus Probable Producing					
Total Reserves mboe	44,283	41,673	30,952	23,873	16,908
Reserves additions mboe	10,951	17,273	12,085	10,890	12,717
FD&A $/boe[2]	33.98	23.35	28.07	25.58	21.43
Recycle Ratio[3]	1.07	1.27	1.27	2.52	2.80
Reserves Replacement[4]	131%	264%	241%	277%	615%
RLI (years)[5]	5.3	6.4	6.2	6.1	8.2
Total Proven					
Total Reserves mboe	81,998	71,577	57,391	49,928	31,376
Reserves additions mboe	18,761	20,738	12,467	22,466	21,851
Change in FDC ($000)	167,823	84,939	(67,100)	262,071	298,429
FD&A $/boe[2]	28.78	23.54	21.82	24.07	26.13
Recycle Ratio[3]	1.26	1.26	1.63	2.68	2.30
Reserves Replacement[4]	225%	317%	249%	572%	1057%
RLI (years)[5]	9.8	11.0	11.5	12.7	15.2
	2017	**2016**	**2015**	**2014**	**2013**
Proven Plus Probable					
Total Reserves mboe	106,652	93,989	76,361	63,565	42,729
Reserves additions mboe	21,003	24,180	17,800	24,750	27,619
Change in FDC ($000)	155,391	66,240	(43,900)	305,248	259,940
FD&A $/boe[2]	25.11	19.42	16.59	23.59	19.28
Recycle Ratio[3]	1.45	1.53	2.14	2.73	3.12
Reserves Replacement[4]	252%	369%	356%	630%	1336%
RLI (years)[5]	12.8	14.4	15.3	16.2	20.7

Notes:

1. *Financial and production information is per the Company's 2017 preliminary unaudited financial statements and is therefore subject to audit.*
2. *Finding, development and acquisition ("FD&A") costs are used as a measure of capital efficiency. The calculation includes all capital costs, including capital spent on acquisitions, for that period plus the change in FDC for that period. F&D as presented herein includes all capital costs, excluding capital spent on acquisitions, for that period plus the change in FDC for that period. This total capital including the change in the FDC is then divided by the change in reserves for that period incorporating all revisions and production for that same period. For example: 2017 Total Proven = ($372,100,000+$167,823,000) / (81,998 mboe-71,577mboe +8,340mboe) = $28.78 per boe. There was no acquisition capital for Raging River in 2017.*

3. *Recycle Ratio is calculated by dividing the operating netback per boe by the FD&A costs for that period. For example: 2017 Total Proven = ($36.36/$28.78) = 1.3. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves.*
4. *The reserves replacement ratio is calculated by dividing the yearly change in reserves before production by the actual annual production for that year. For example: 2017 Total Proven = (81,998 mboe -71,577 mboe +8,340 mboe)/8,340 mboe = 225%.*
5. *RLI is calculated by dividing the reserves in each category by the average annual production for that period. For example 2017 Total Proven = (81,998 mboe) / (22,850 boe*.365) = 9.8 years.*

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2017, reflected in the Sproule Report, used to estimate the reserves volumes and associated values in the Engineering Report. These price assumptions were provided to Raging River by Sproule and were Sproule's then current forecast at the date of the Sproule Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS (1)
as of December 31, 2017
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/Bbl)	Canadian Light Sweet 40º API ($Cdn/Bbl)	Cromer LSB 35º API ($Cdn/Bbl)	Natural Gas AECO-C Spot ($Cdn/ MMBtu)	NGLs Edmonton Propane ($Cdn/Bbl)	NGLs Edmonton Butanes ($Cdn/Bbl)	Condensate at Edmonton ($Cdn/Bbl)	Operating Cost Inflation Rates %/Year	Capital Cost Inflation Rates %/Year	Exchange Rate (2) ($Cdn/$US)
Forecast(3)										
2018	55.00	65.44	64.44	2.85	26.06	48.73	67.72	0.0%	0.0%	0.790
2019	65.00	74.51	73.51	3.11	32.84	55.49	75.61	2.0%	2.0%	0.820
2020	70.00	78.24	77.24	3.65	35.41	57.65	78.82	2.0%	2.0%	0.850
2021	73.00	82.45	81.45	3.80	37.85	60.12	82.35	2.0%	2.0%	0.850
2022	74.46	84.10	83.10	3.95	39.29	61.32	84.07	2.0%	2.0%	0.850
2023	75.95	85.78	84.78	4.05	40.25	62.55	85.82	2.0%	2.0%	0.850

Thereafter Escalation rate of 2.0%

Notes:

1. *This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.*
2. *The exchange rate used to generate the benchmark reference prices in this table.*
3. *As at December 31, 2017.*

Additional corporate information can be found on our website at www.rrexploration.com or on www.sedar.com.

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FORWARD LOOKING STATEMENTS: This press release contains forward-looking statements, including, but not limited to, forward-looking statements relating to the expected details of the first quarter of 2018 capital program, including timing for finishing all drilling and completion operations, total capital expenditures and the number and locations of wells to be drilled; expected details of the targets, timing and locations of wells to be drilled by Raging River in the east Duvernay shale basin and expected timing of filing the Company's Annual Information Form. In addition, the *use of any of the words "guidance", "initial, "scheduled", "can", "will", "prior to", "estimate", "anticipate", "believe", "should", "unaudited", "forecast", "future", "continue", "may", "expect", and similar expressions are intended to identify forward-looking statements. 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 herein are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning the success of optimization and efficiency improvement projects, the availability of capital, current legislation, pipeline, transportation and processing 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 expectations as to commodity prices. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects, capital expenditures, acquisitions or other corporate transactions; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price and exchange rate fluctuations, changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. To the extent any guidance or forward looking statements herein constitute a financial outlook, they are included herein to provide readers with an understanding of management's plans and assumptions for budgeting purposes and readers are cautioned that the information may not be appropriate for other purposes. Additional information on these and other factors that could affect Raging River's operations and financial results are included in the Company's Annual Information Form and other reports on file with Canadian securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com).*

The forward-looking statements contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

RESERVES AND PRODUCTION DISCLOSURE: Reserves and production information presented herein has been presented on a gross basis which are the Company's total working interest share before the deduction of any royalties and without including any royalty interests of the Company. The reserves estimates presented herein have been evaluated by Sproule and GLJ in accordance with NI 51-101 and the COGE Handbook and are effective December 31, 2017 using Sproule's December 31, 2017 forecast pricing. GLJ evaluated the reserves associated with the Company's interests in the east Duvernay shale basin and Sproule evaluated the reserves associated with the remainder of the Company's oil and gas interests. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. It should not be assumed that the estimates of future net revenues presented herein represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Company''s crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

BARRELS OF OIL EQUIVALENT: The term "boe" or barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Additionally, given that the value ratio based on the current price of crude oil, as compared to natural gas, is significantly different from the energy equivalency of 6:1; utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

OIL AND GAS METRICS: This press release contains a number of oil and gas metrics, including F&D or FD&A, recycle ratio, reserves replacement, and reserves life index or RLI, 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.

INITIAL PRODUCTION RATES; References in this press release to initial production rates, other short-term production rates or initial performance measures relating to new wells are useful in confirming the presence of hydrocarbons, *however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered to be preliminary.*

NON-IFRS MEASURES: This document contains the terms "net debt" and "operating netback", which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the calculation of similar measures by other companies. Management believes "net debt" is a useful supplemental measure of the total amount of current and long-term debt of the Company. Mark-to-market risk management contracts are excluded from the net debt calculation. Management believes "operating netback" is a useful supplemental measure of the amount of revenues received after royalties and operating and transportation costs. Additional information relating to these non-IFRS measures, including the reconciliation between funds flow from operations and cash flow from operating activities, can be found in the Company's most recent management's discussion and analysis, which may be accessed through the SEDAR website (www.sedar.com).