NEWS RELEASE

February 28, 2019

WHITECAP RESOURCES INC. ANNOUNCES FOURTH QUARTER, YEAR END 2018 RESULTS AND 2018 RESERVES EVALUATION

CALGARY, ALBERTA – Whitecap Resources Inc. ("Whitecap" or the "Company") (TSX: WCP) is pleased to report its operating and audited financial results for the year ended December 31, 2018.

Selected financial and operating information is outlined below and should be read with Whitecap's audited annual consolidated financial statements and related Management's Discussion and Analysis ("MD&A") and Annual Information Form ("AIF") which are available at www.sedar.com and on our website at www.wcap.ca.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31		Twelve months ended December 31	
Financial ($000s except per share amounts)	2018	2017	2018	2017
Petroleum and natural gas revenues	272,397	291,376	1,519,845	1,031,240
Net income (loss)	6,966	(231,729)	65,128	(123,968)
Basic ($/share)	(0.02)	(0.61)	0.16	(0.33)
Diluted ($/share)	(0.02)	(0.61)	0.15	(0.33)
Funds flow	138,810	143,543	704,420	508,627
Basic ($/share)	0.33	0.38	1.69	1.37
Diluted ($/share)	0.33	0.38	1.67	1.36
Dividends paid or declared	33,611	27,476	132,295	104,926
Per share	0.08	0.07	0.32	0.28
Total payout ratio (%) [1]	79	59	81	87
Expenditures on PP&E	76,485	57,698	440,499	339,761
Property acquisitions	15,157	939,015	35,249	970,883
Property dispositions	(205)	(8,777)	(11,681)	(14,598)
Corporate acquisition	-	-	53,916	-
Net debt	1,300,410	1,295,906	1,300,410	1,295,906
Operating				
Average daily production				
Crude oil (bbls/d)	57,072	44,699	58,511	43,589
NGLs (bbls/d)	4,656	3,634	4,397	3,415
Natural gas (Mcf/d)	68,739	68,244	69,042	62,676
Total (boe/d)	73,185	59,707	74,415	57,450
Average realized price [2]				
Crude oil ($/bbl)	47.22	64.54	66.46	58.61
NGLs ($/bbl)	29.52	37.45	35.90	30.57
Natural gas ($/Mcf)	1.87	2.14	1.70	2.65
Total ($/boe)	40.46	53.04	55.96	49.18
Netbacks ($/boe)				
Petroleum and natural gas revenues	40.46	53.04	55.96	49.18
Tariffs	(0.60)	(1.15)	(0.72)	(1.43)
Processing income	0.44	0.56	0.45	0.46
Blending revenue	1.13	-	0.47	-
Petroleum and natural gas sales	41.43	52.45	56.16	48.21
Realized hedging gain (loss)	4.77	(2.19)	(2.36)	(1.15)
Royalties	(6.77)	(7.41)	(9.87)	(6.89)
Operating expenses	(12.28)	(11.44)	(12.05)	(11.07)
Transportation expenses	(2.20)	(1.93)	(2.17)	(1.63)
Blending expenses	(0.92)	-	(0.38)	-
Operating netbacks [1]	24.03	29.48	29.33	27.47
Share information (000s)				
Common shares outstanding, end of period	414,063	418,029	414,063	418,029
Weighted average basic shares outstanding	415,714	379,326	417,061	371,848
Weighted average diluted shares outstanding	418,784	381,574	420,587	373,944

Notes:

(1) Total payout ratio and operating netbacks do not have a standardized meaning under GAAP. Refer to non-GAAP measures in this press release for additional disclosure and assumptions.

(2) Prior to the impact of hedging activities and tariffs.

MESSAGE TO SHAREHOLDERS

Whitecap delivered another year of double-digit production per debt-adjusted share growth of 16% to achieve record annual production of 74,415 boe/d in 2018 along with solid funds flow per fully diluted share of $1.67 per boe, an increase of 23% from the prior year.

Expenditures on property, plant and equipment ("PP&E") in 2018 of $440.5 million was approximately $10 million lower than projected as we limited capital expenditures late in the fourth quarter in response to the wide crude oil price differentials. The capital program included the drilling of 261 (216.3 net) wells and was the largest in the Company's history allowing us to once again deliver on our business model of self-funded growth including dividends despite the volatility in commodity prices. In 2018, we generated funds flow of $704.4 million, invested $440.5 million for organic production growth and made dividend payments of $132.3 million which resulted in $131.6 million of free funds flow.

In addition to strong operational execution, we completed numerous small tuck-in acquisitions which consolidated working interests in our core operating areas totaling $35.2 million. We completed a corporate acquisition for $56.8 million, net of acquired working capital, which consolidated our working interest in southwest Saskatchewan adding 1,000 boe/d of production (95% oil) and 60 low risk, top tier drilling locations to our inventory. We also continued to high-grade our asset base by disposing of non-core assets totaling $11.7 million.

Shareholder returns were enhanced in 2018 as we increased the monthly dividend by 5% to $0.027 per share ($0.324 per share annualized) from $0.0257 per share ($0.3084 per share annualized) and reduced our common shares outstanding by 6.3 million shares through Whitecap's normal course issuer bid.

Whitecap has a strong balance sheet with net debt at $1.3 billion on debt capacity of $1.7 billion, providing significant unutilized capacity for financial flexibility. We have $595 million of debt termed out to 2022 - 2026 at attractive fixed long-term interest rates averaging 3.6% per annum with no near-term maturities and the balance of debt on our credit facility that has a four year term. In addition, the debt to earnings before interest, taxes, depreciation and amortization ("EBITDA") ratio was 1.7x in 2018. (1)

(1) Refer to Note 11(a) "Bank Debt" in the audited annual consolidated financial statements.

2018 FINANCIAL HIGHLIGHTS

- Achieved average production of 73,185 boe/d in Q4/18 compared to 59,707 boe/d in Q4/17, an increase of 23% (11% per debt-adjusted share). Average production for the full year was a record 74,415 boe/d compared to 57,450 boe/d in 2017, an increase of 30% (16% per debt-adjusted share).

- Realized a strong operating netback (prior to hedges) of $31.69/boe compared to $28.62/boe in 2017, an 11% increase which demonstrates the quality of our oil-weighted asset base.

- Realized net hedging gains of $32.1 million on commodity contracts price and FX contracts in Q4/18 and net hedging losses of $64.0 million for the full year. We have been successful at protecting our funds flow and mitigating commodity price volatility through our ongoing risk management program which has resulted in a net hedging gain of $129.6 million on commodity price and FX contracts over the last five years. We currently have 42% of 2019 and 13% of 1H/20 crude oil production (net of royalties) hedged using a combination of swaps and costless collars. See Note 5 to the audited annual consolidated financial statements for further details.

- Generated funds flow of $704.4 million ($1.67 per share), an increase of 38% (23% per share) compared to the prior year. Higher production volumes and realized prices in 2018 resulted in significantly higher funds flow.

- Expenditures on PP&E were $440.5 million compared to $339.8 million in the prior year. We drilled 261 (216.3 net) wells in 2018, including 135 (127.4 net) wells in west central Saskatchewan, 60 (41.2 net) wells in southwest Saskatchewan, 16 (9.6 net) wells in southeast Saskatchewan, 21 (17.5 net) wells in west central Alberta, and 29 (20.6 net) wells in northwest Alberta and British Columbia.

- The total payout ratio was 81% in 2018 resulting in free funds flow of $131.6 million compared to 87% and free funds flow of $63.9 million in the prior year.

- Supported by strong operational execution, stronger crude oil prices and free funds flow, we increased our dividend by 5% in June 2018 and paid out $132.3 million of cash dividends to shareholders in the year.

- Reduced our common shares outstanding by 6.3 million shares through the normal course issuer bid.

- As part of our annual credit facility review, we transitioned from a borrowing-based structure with lending capacity redetermined on a semi-annual basis, to a financial covenant-based revolving facility with an extendible four-year term governed by our existing leverage and interest coverage ratios. Our balance sheet remains strong with 2018 debt to EBITDA ratio of 1.7x and an undrawn bank credit facility of approximately $443.8 million.

2018 OPERATIONAL HIGHLIGHTS

- Operational performance at our Weyburn property remained exceptional. For 2018 we had budgeted operating income of $170 million and capital expenditures of $60 million to keep production flat at 14,800 boe/d. Actual operating income for 2018 was $178.6 million, capital expenditures were $48.9 million including costs to purchase CO_2 and average production was 14,700 boe/d. Capital expenditures of $48.9 million included 6 (3.7 net) re-drills, 12 (7.5 net) infill wells to optimize recovery in developed areas and the drilling of 2 (1.2 net) producers and 2 (1.2 net) injectors to expand the CO_2 flood. The Weyburn team was able to optimize our CO_2 injection volumes and placement which resulted in a CO_2 capital cost reduction of $9 million. In addition to these capital savings, we also reduced operating costs by 8% to $12.90/boe.

- Financial and operating results in southwest Saskatchewan continued to exceed expectations. In 2018, operating income from this area was $168.8 million and $81.4 million in capital expenditures was invested to grow average production by 11% to 15,000 boe/d. Operating costs in this area were also reduced by 10% to $12.47/boe. We successfully expanded into a new play area in the Lower Shaunavon, drilling 2 (2.0 net) wells in 2018 and anticipate drilling 5 (4.0 net) additional delineation wells in the first half of 2019 to potentially de-risk more than 200 locations we have identified in the Lower Shaunavon.

- The Viking resource play in west central Saskatchewan continued to supply predictable growth for the Company in 2018. Average production in this area increased 10% to 12,200 boe/d generating $192.0 million of operating income on capital expenditures of $121.6 million. We have seen very encouraging results both in the revitalization of the Kerrobert waterflood as well as the expansion and optimization of the Dodsland/Eagle Lake legacy flood. This expansion included the conversion of an additional 12 wells to injection which have the potential to support an additional 15 producing wells. To date, we have seen positive production response from over 40 wells in the Kerrobert waterflood reactivation.

- In the Deep Basin, we continue to see exceptional results from our Cardium program in Wapiti which included the drilling of 16 (10.4 net) wells and the construction of central production handling facilities. The impact of this activity increased production by 50% to 8,200 boe/d, and we were able to reduce operating costs by a further 5% to $9.40/boe. With the recent expansion of our fluid and gas handling facilities in Wapiti, our per unit operating costs are expected to decrease further as we continue to develop this area.

- The Cardium production in west central Alberta has remained stable year over year at 15,200 boe/d with capital spending concentrated in West Pembina and Ferrier. 2018 operating income in the Cardium was $161 million on capital expenditures of $65.5 million. Since 2014, we have focused on piloting waterflood re-development designs in our operated West Pembina unit including the reactivation of vertical injection wells, and the conversion and drilling of horizontal injection wells. In West Pembina, we drilled 10 (8.0 net) horizontal oil producers and 1 (0.9 net) horizontal injector as part of the final pilot waterflood redevelopment phase as we have been seeing better than expected response to our unstimulated horizontal injector designs and, as a result, we will be proceeding to full re-development of this operated West Pembina unit. In Ferrier, we drilled 5 (4.7 net) wells in the main legacy waterflood confirming the economic potential of the remaining lands in the area. Operational results have met expectations and full horizontal development of the legacy waterflood will continue in 2019 and beyond.

2018 RESERVE HIGHLIGHTS

Net Asset Value (BTAX NPV10)

- PDP net asset value per share increased 13% to $5.44 compared to $4.82 in the prior year.
- TP net asset value per share increased 5% to $8.60 compared to $8.17 in the prior year.
- TPP net asset value per share increased 5% to $13.08 compared to $12.50 in the prior year.

Proved Developed Producing ("PDP")

- Increased PDP reserves by 14% per debt-adjusted share to 225.4 MMboe.
- Total PDP reserve additions of 30.5 MMboe replaced 112% of production at a finding, development and acquisition ("FD&A") cost of $17.01/boe, excluding changes in future development cost ("FDC"), which results in a recycle ratio of 1.7 times.
- PDP reserves represent 64% of the TP reserves, consistent with the prior year.

Total Proved ("TP")

- Increased TP reserves by 15% per debt-adjusted share to 354.6 MMboe.
- Total TP reserve additions of 34.7 MMboe replaced 128% of production at an FD&A cost of $14.94/boe, excluding FDC, which results in a recycle ratio of 2.0 times.
- TP reserves represent 72% of the TPP reserves consistent with the prior year.

Total Proved Plus Probable ("TPP")

- Increased TPP reserves by 14% per debt-adjusted share to 489.5 MMboe.
- Total TPP reserve additions of 33.7 MMboe replaced 124% of production at an FD&A cost of $15.37/boe, excluding FDC, which results in a recycle ratio of 1.9 times.

OUTLOOK

Whitecap will continue to focus on delivering total shareholder returns in excess of 10% through a combination of production per share growth and the dividend yield and, at the same time, keeping balance sheet strength a priority.

For the 2019 year, our priorities include 1) maintaining a strong and flexible balance sheet to provide capacity for capturing additional opportunities, 2) paying a sustainable and growing dividend, 3) continued commitment to capital spending and dividend payments within funds flow, and 4) strong production per share growth in the back half of 2019.

In 2019, we have elected to start the year with a cautious and defensive capital program which will generate a meaningful amount of free funds flow in the first half of the year and provide maximum optionality for funds placement in the second half of the year. We anticipate growing production by 7% to 78,000 boe/d in the fourth quarter from the same period in the prior year. For 2020 and 2021, we have forecasted annual organic production growth at the high end of our targeted 6% to 8% per share in combination with dividend increases. We anticipate that this production growth will allow us to generate a significant amount of free funds flow and allow us to continue to enhance shareholder returns.

On behalf of our board of directors and the Whitecap management team, we would like to thank our shareholders for your ongoing support through this volatile business environment. We look forward to providing strong operational and financial updates as we progress through 2019.

2018 RESERVES REVIEW

Our 2018 year end reserves were evaluated by independent reserves evaluator McDaniel & Associates Consultants Ltd. ("McDaniel") in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") as of December 31, 2018. The reserves evaluation was based on the average forecast pricing of McDaniel's, GLJ Petroleum Consultants and Sproule Associates Limited and foreign exchange rates at January 1, 2019 which is available on McDaniel's website at www.mcdan.com.

Reserves included are Company share reserves which are the Company's total working interest reserves before the deduction of any royalties and include any royalty interests payable to the Company. Additional reserve information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR on or before March 31, 2018. The numbers in the tables below may not add due to rounding.

Summary of Reserves
Reserves as at December 31, 2018

	Company Share Reserves			
Description	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Total (Mboe)
Proved producing	181,376	185,377	13,101	225,374
Proved non-producing	2,750	3,620	82	3,435
Proved undeveloped	97,738	114,728	8,889	125,748
Total proved	281,864	303,725	22,072	354,557
Probable	103,332	130,493	9,814	134,894
Total proved plus probable	385,196	434,218	31,885	489,451

Net Present Values

Summary of Before Tax Net Present Values (Forecast Pricing)
As at December 31, 2018

	Before Tax Net Present Value ($MM) (1)				
	Discount Rate				
Description	0%	5%	10%	15%	20%
Proved producing	6,828	4,636	3,516	2,851	2,412
Proved non-producing	116	81	61	49	40
Undeveloped	3,043	1,929	1,267	859	595
Total proved	9,987	6,646	4,845	3,759	3,047
Probable	6,103	3,070	1,882	1,302	973
Total proved plus probable	16,090	9,716	6,727	5,061	4,020
Per fully diluted share	38.28	23.11	16.00	12.04	9.56

(1) Includes abandonment and reclamation costs as defined in NI 51-101.

Future Development Costs

FDC reflects the best estimate of the capital cost to produce reserves. FDC associated with our TPP reserves at year end 2018 is $3.4 billion undiscounted ($2.2 billion discounted 10%) and includes polymer and CO_2 purchases for our southwest and southeast Saskatchewan enhanced oil recovery projects. TPP and TP FDC for these two items is $805 million undiscounted ($278 million discounted 10%).

Also included in FDC are 1,405 (1,172.8 net) proved plus probable booked locations of which 600 (525.5 net) are extended reach horizontal ("ERH") wells. Booked locations represent 50% of Whitecap's total inventory at December 31, 2018 of 2,834 (2,251.4 net) locations of which 894 (787.7net) are ERH wells.

($000s)	Total Proved	Total Proved plus Probable
2019	495,917	506,094
2020	495,229	499,271
2021	462,964	497,885
2022	420,076	502,090
2023	341,937	399,039
Remainder	966,040	1,038,011
Total FDC, Undiscounted	3,182,163	3,442,389
Total FDC, Discounted at 10%	2,050,368	2,215,218

Performance Measures (Excluding FDC)

The following table highlights our finding and development ("F&D") and FD&A costs and associated recycle ratios, excluding FDC, based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2018	**2017**	**2016**	**Three Year Weighted Average**
Proved Developed Producing				
F&D costs (1)	$15.06	$12.48	$14.42	$13.95
F&D recycle ratio (2)	1.9x	2.2x	1.8x	2.0x
FD&A costs (3)	$17.01	$13.55	$14.31	$15.03
FD&A recycle ratio (2)	1.7x	2.0x	1.8x	1.8x
Total Proved				
F&D costs (1)	$14.28	$13.71	$9.33	$12.75
F&D recycle ratio (2)	2.1x	2.0x	2.8x	2.3x
FD&A costs (3)	$14.94	$10.97	$10.96	$12.43
FD&A recycle ratio (2)	2.0x	2.5x	2.4x	2.3x
Total Proved Plus Probable				
F&D costs (1)	$15.67	$12.71	$9.59	$12.96
F&D recycle ratio (2)	1.9x	2.2x	2.8x	2.3x
FD&A costs (3)	$15.37	$8.61	$8.03	$10.95
FD&A recycle ratio (2)	1.9x	3.2x	3.3x	2.7x

(1) F&D costs are calculated as development capital of $426.3 million divided by the change in reserves that are characterized as development for the period.
(2) Recycle ratio is calculated as operating netback divided by F&D or FD&A costs. Our operating netback in 2018 was $29.33/boe.
(3) FD&A costs are calculated as the sum of development capital of $426.3 million plus acquisition capital of $91.7 million, divided by the change in total reserves, other than from production, for the period.

Performance Measures (Including FDC)

The following table highlights our F&D and FD&A costs and associated recycle ratios, including FDC, based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2018	**2017**	**2016**	**Three Year Weighted Average**
Proved Developed Producing				
F&D costs [(1)]	$13.06	$11.25	$14.46	$12.78
F&D recycle ratio [(2)]	2.2x	2.4x	1.8x	2.2x
FD&A costs [(3)]	$15.15	$21.68	$15.78	$17.69
FD&A recycle ratio [(2)]	1.9x	1.3x	1.7x	1.6x
Total Proved				
F&D costs [(1)]	$22.70	$13.37	$2.42	$13.87
F&D recycle ratio [(2)]	1.3x	2.1x	10.9x	4.2x
FD&A costs [(3)]	$23.30	$21.53	$13.32	$19.98
FD&A recycle ratio [(2)]	1.3x	1.3x	2.0x	1.5x
Total Proved Plus Probable				
F&D costs [(1)]	$24.83	$12.66	$2.34	$14.38
F&D recycle ratio [(2)]	1.2x	2.2x	11.3x	4.3x
FD&A costs [(3)]	$24.04	$17.05	$11.51	$18.14
FD&A recycle ratio [(2)]	1.2x	1.6x	2.3x	1.6x

(1) F&D costs are calculated as the sum of development capital of $426.3 million plus the change in FDC for the period of -$56.5 million (PDP), $251.5 million (TP) and $249.2 million (TPP), divided by the change in reserves that are characterized as development for the period.
(2) Recycle ratio is calculated as operating netback divided by F&D or FD&A costs. Our operating netback in 2018 was $29.33/boe.
(3) FD&A costs are calculated as the sum of development capital of $426.3 million plus acquisition capital of $91.7 million plus the change in FDC for the period of -$56.5 million (PDP), $290.0 million (TP) and $292.0 million (TPP), divided by the change in total reserves, other than from production, for the period.

Production Replacement and Reserve Life Index

The following table highlights our production replacement and reserve life index ("RLI") based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2018	**2017**	**2016**	**Three Year Weighted Average**
Proved Developed Producing				
Production replacement [(1)]	112%	449%	313%	288%
RLI (years) [(2)]	8.4	10.2	8.1	9.0
Total Proved				
Production replacement [(1)]	128%	555%	409%	359%
RLI (years) [(2)]	13.3	15.9	13.6	14.3
Total Proved Plus Probable				
Production replacement [(1)]	124%	707%	559%	453%
RLI (years) [(2)]	18.3	22.2	19.3	20.0

(1) Production replacement ratio is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production. Whitecap's production averaged 74,415 boe/d in 2018.
(2) RLI is calculated as total Company share reserves divided by the annualized fourth quarter actual production of 73,185 boe/d.

Conference Call and Webcast

Whitecap has scheduled a conference call and webcast to begin promptly at 9:00 am MT (11:00 am ET) on Thursday, February 28, 2019.

The conference call dial-in number is: 1-888-390-0605 or (587) 880-2175 or (416) 764-8609

A live webcast of the conference call will be accessible on Whitecap's website at www.wcap.ca by selecting *"Investors"*, then *"Presentations & Events"*. Shortly after the live webcast, an archived version will be available for approximately 14 days.

An archived recording of the conference call will also be available approximately two hours after the completion of the call until March 14, 2019 by dialing 1-888-390-0541, passcode 737521#.

Note Regarding Forward-Looking Statements

This press release contains forward-looking statements and forward-looking information (collectively "forward-looking information") within the meaning of applicable securities laws relating to the Company's plans and other aspects of our anticipated future operations, management focus, strategies, financial, operating and production results and business opportunities. Forward-looking information typically uses words such as "anticipate", "believe", "continue", "trend", "sustain", "project", "expect", "forecast", "budget", "goal", "guidance", "plan", "objective", "strategy", "target", "intend", "estimate", or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future, including statements about our strategy, plans, objectives, priorities and focus; the Company's hedging program; the number of wells to be drilled and the timing thereof; the benefits to be derived from the Dodsland/Eagle Lake legacy flood; expectations that per unit operating costs will decrease in Wapiti; expectation that full horizontal development of the legacy waterflood will continue in Ferrier in 2019 and beyond; the sustainability of our dividend; the expectation that our dividend will increase; our ability to deliver shareholder returns in excess of 10 percent; future development costs; quantity of drilling locations in inventory; generating free funds flow in the first half of 2019; expectations with respect to 2019, 2020 and 2021 production growth and the benefits to be derived therefrom. Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking information is based on certain key expectations and assumptions made by our management, including expectations and assumptions concerning prevailing commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; performance; business prospects and opportunities; the availability and cost of financing, labour and services; the impact of increasing competition; ability to efficiently integrate assets and employees acquired through acquisitions, ability to market oil and natural gas successfully and our ability to access capital.

Although we believe that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Whitecap can give no assurance that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature they involve inherent risks and uncertainties. These include, but are not limited to: the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, production, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; marketing and transportation; loss of markets; environmental risks; competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions; ability to access sufficient capital from internal and external sources; failure to obtain required regulatory and other approvals; reliance on third parties and pipeline systems; and changes in legislation, including but not limited to tax laws, royalties and environmental regulations. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, the forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits that we will derive therefrom. Management has included the above summary of assumptions and risks related to forward-looking information provided in this press release in order to provide security holders with a more complete perspective on our future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect our operations or financial results are included in reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

These forward-looking statements are made as of the date of this press release and we disclaim any intent or obligation to update publicly any forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Oil and Gas Advisories

All reserve references in this press release are "Company share reserves". Company share reserves are the Company's total working interest reserves before the deduction of any royalties and including any royalty interests payable to the Company.

It should not be assumed that the present worth of estimated future cash flow 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 reserve estimates of Whitecap'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.

"Boe" means barrel of oil equivalent based on 6 mcf of natural gas to 1 bbl of oil. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 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. In addition, 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 on a 6:1 basis may be misleading as an indication of value.

This press release contains metrics commonly used in the oil and natural gas industry which have been prepared by management, such as "recycle ratio", "operating netback", "F&D costs", "FD&A costs", "production replacement ratio", "reserve life index", "development capital", "acquisition capital"; "net asset value per share" "production per debt-adjusted share", and "reserves per debt-adjusted share". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

"**Acquisition capital**" includes net property acquisitions less any non-cash amounts and the announced purchase price of corporate acquisition including any estimated working capital deficit or surplus rather than the amounts allocated to property, plant and equipment for accounting purposes and the aggregate exploration and development capital spending within the year on reserves that are categorized as acquisitions less the disposition of certain processing facilities.

"**Development capital**" means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development. Development capital excludes capitalized administration costs.

"**F&D costs**" are calculated as the sum of development capital plus the change in FDC for the period when appropriate, divided by the change in reserves that are characterized as development for the period.

"**FD&A costs**" are calculated as the sum of development capital plus acquisition capital plus the change in FDC for the period when appropriate, divided by the change in total reserves, other than from production, for the period

"**Net asset value per share**" is based on present value of future net revenues discounted at 10% before tax on PDP, TP or TPP reserves, plus our internally estimated undeveloped land value of $62.1 million, net of estimated net debt at year end divided by the number of fully diluted shares outstanding at year end.

"**Operating netback**" see "Non-GAAP Measures".

"**Production per debt-adjusted share**" is calculated by dividing production for the period by debt adjusted weighted average fully diluted shares. Debt adjusted weighted average fully diluted shares is calculated by dividing the change in net debt in the period by the average share price for the period. A further adjustment is made to normalize for the impact of the Southeast Saskatchewan acquisition which closed on December 14, 2017. The adjustment to production and weighted average fully diluted shares assumes the acquisition occurred at the beginning of the period.

"**Production replacement ratio**" is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production.

"**Recycle ratio**" is measured by dividing operating netback by F&D or FD&A cost per boe for the year.

"**Reserve life index**" or "**RLI**" is calculated as total Company share reserves divided by annualized fourth quarter actual production.

“**Reserves per debt-adjusted share**” is calculated by dividing reserves by debt adjusted shares. Debt adjusted shares is calculated by dividing the change in net debt in the period by the average share price for the period.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare our operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

Drilling Locations

This press release discloses drilling inventory in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from McDaniel & Associates Consultants Ltd.'s reserves evaluation effective December 31, 2018 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our 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. Of the 2,834 (2,251.4 net) total drilling locations identified herein, 1,292 (1,091.0 net) are proved locations, 113 (81.8 net) are probable locations and 1,429 (1,078.6 net) are unbooked locations. Of the 894 (787.7 net) ERH wells drilling locations identified herein, 596 (522.0 net) are proved locations, 4 (3.5 net) are probable locations and 294 (262.2 net) are unbooked locations. Of the 60 (46.9 net) drilling locations acquired in the 2018 corporate acquisition identified herein, 34 (24.3 net) are proved locations, 4 (3.4 net) are probable locations and 22 (19.2 net) are unbooked locations. Of the 200 (165.5 net) Lower Shaunavon drilling locations identified herein, 10 (9.1 net) are proved locations, 3 (2.4 net) are probable locations and 187 (154 net) are unbooked locations. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we 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 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 have been de-risked 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.

Non-GAAP Measures

This press release includes non-GAAP measures as further described herein. These non-GAAP measures do not have a standardized meaning prescribed by International Financial Reporting Standards (“IFRS” or, alternatively, “GAAP”) and, therefore, may not be comparable with the calculation of similar measures by other companies. See the Company’s Management’s Discussion and Analysis of financial condition and results of operation for the year ended December 31, 2018 for a reconciliation of the non-GAAP measures.

“Free funds flow” represents funds flow less dividends paid or declared and expenditures on PP&E. Management believes that free funds flow provides a useful measure of Whitecap’s capital reinvestment and dividend policy.

“Operating income” is determined by adding blending revenue and processing income, deducting realized hedging losses or adding realized hedging gains and deducting tariffs, royalties, operating expenses, transportation expenses and blending expenses from petroleum and natural gas revenues. Operating income is used in operational and capital allocation decisions. Management uses operating income to better analyze performance among its management units.

“Operating netbacks” are determined by dividing Operating Income by total production for the period. Operating netbacks are per boe measures used in operational and capital allocation decisions. Presenting operating netbacks on a per boe basis allows management to better analyze performance against prior periods on a comparative basis.

“**Operating netbacks (prior to hedges)**” are determined by adding blending revenue and processing income, and deducting tariffs, royalties, operating expenses, transportation expenses and blending expenses from petroleum and natural gas revenues. Operating netbacks (prior to hedges) are per boe measures used in operational and capital allocation decisions excluding the impact of the Company’s hedging program. Presenting operating netbacks (prior to hedging) on a per boe basis allows management to better analyze performance against prior periods on a comparative basis.

“Total payout ratio” is calculated as dividends paid or declared plus expenditures on PP&E, divided by funds flow. Management believes that total payout ratio provides a useful measure of Whitecap’s capital reinvestment and dividend policy, as a percentage of the amount of funds flow.

For further information:

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