



Cona Resources Ltd. Announces 2017 Year-End Reserves Information

CALGARY, ALBERTA (February 21, 2018) – Cona Resources Ltd. (“Cona” or the “Company”) (TSX: CONA) announces its 2017 year-end reserves information.

Cona's year-end 2017 reserves are indicative of the Company's unique low decline, high quality oil-weighted asset base. With over 90% of the Company's production under natural water drive, waterflood, polymer flood or steam assisted gravity drainage (“SAGD”), we have been able to grow our reserves base while spending only 64% of our 2017 funds from operations during a period of suppressed commodity prices. We have delivered increases in all three reserve categories (proved developed producing (“PDP”), total proved (“1P”) and proved plus probable (“2P”)), at low single digit finding and development costs. Cona's reserves are also uniquely positioned having a long reserve life index (“RLI”) on a 2P basis of over 21 years, with 64% of those reserves in the lower risk 1P reserves category.

2017 RESERVE HIGHLIGHTS

- Before deducting annual production, PDP reserves increased by 7.1 million boe or 14%, 1P reserves increased by 13.6 million boe or 18% and 2P reserves increased by 8.0 million boe or 6%. After deducting annual production, PDP reserves increased by 0.8 million boe or 2%, 1P reserves increased by 7.3 million boe or 10% and 2P reserves increased by 1.7 million boe or 1%.
- Positive heavy oil technical revisions of 7.1 million bbl on 1P reserves and 2.5 million bbl on 2P reserves, largely attributed to the Cactus Lake property, are further recognition of Cona's successful polymer flood.
- Finding, development and acquisition (“FD&A”) costs were favourable for an oil weighted asset base at \$3.54 per boe for 2P reserves, \$7.01 per boe for 1P reserves and \$6.58 per boe for PDP reserves, including future development capital (“FDC”).
- Finding and development (“F&D”) costs were similarly strong at \$3.72 per boe for 2P reserves, \$7.11 per boe for 1P reserves and \$6.82 per boe for PDP reserves, including FDC.
- The strong 2017 FD&A costs resulted in exceptional recycle ratios of over three times for PDP and 1P reserves and over six times for 2P reserves based on a 2017 operating netback of \$21.85 per boe.
- At year-end 2017, PDP reserves accounted for 40% of 2P reserves and 1P reserves accounted for 64% of 2P reserves.
- Cona's RLI at December 31, 2017 is 21.2 years based on 2P reserves and 13.5 years based on 1P reserves.
- Before-tax net present value for 1P and 2P reserves at December 31, 2017, based on forecast prices and discounted at 10%, is \$1.1 billion and \$1.6 billion, respectively.

RESERVES

Independent Reserves Evaluation

Cona's reserves were independently evaluated by Ryder Scott Company-Canada ("Ryder Scott") as at December 31, 2017 in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") (the "Reserves Evaluation"). The Reserves Evaluation was based on forecast pricing and foreign exchange rates as outlined in the table titled "Forecast Prices in 2017 Reserves Evaluation".

Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without the inclusion of any royalty interest) unless otherwise noted. In addition to the information disclosed in this news release, more detailed information will be included in Cona's Annual Information Form ("AIF") for the year ended December 31, 2017, which will be available on Cona's website at www.conaresources.com and on SEDAR at www.sedar.com on or before March 30, 2018.

Summary of Reserves as at December 31, 2017⁽¹⁾⁽²⁾

	Heavy Oil (Mbbbl)	Natural Gas (MMcf)	Oil Equivalent (Mboe)	% of Proved Plus Probable Reserves
Proved				
Developed producing	51,471	3,251	52,013	40
Developed non-producing	411	-	411	-
Undeveloped	30,050	1,189	30,248	24
Total proved	81,931	4,440	82,671	64
Total probable	46,322	2,176	46,685	36
Total proved plus probable	128,253	6,616	129,356	100

Notes:

- (1) Based on escalated prices and costs.
- (2) Figures may not add due to rounding.

Reserves Reconciliation⁽¹⁾⁽²⁾

	Heavy Oil (Mbbbl)	Natural Gas (MMcf)	Oil Equivalent (Mboe)
Proved			
December 31, 2016	74,152	7,282	75,366
Extensions and improved recovery	2,105	66	2,116
Discoveries	-	-	-
Economic factors	(1,032)	(328)	(1,087)
Infill drilling	5,877	239	5,917
Dispositions	(56)	-	(56)
Technical revisions ⁽³⁾	7,071	(2,268)	6,693
Production	(6,186)	(550)	(6,278)
December 31, 2017	81,931	4,440	82,671

	Heavy Oil (Mbbbl)	Natural Gas (MMcf)	Oil Equivalent (Mboe)
Proved plus probable			
December 31, 2016	125,774	11,308	127,658
Extensions and improved recovery	2,354	9	2,356
Discoveries	-	-	-
Economic factors	(1,329)	(572)	(1,424)
Infill drilling	5,221	233	5,260
Dispositions	(92)	-	(92)
Technical revisions ⁽³⁾	2,511	(3,816)	1,875
Production	(6,186)	(550)	(6,278)
December 31, 2017	128,253	6,616	129,356

Notes:

- (1) Based on escalated prices and costs.
- (2) Figures may not add due to rounding.
- (3) Technical revisions impacting proved plus probable reserves as at December 31, 2017 as compared to December 31, 2016 are primarily a result of improved performance in the polymer flood.

Summary of Net Present Values⁽¹⁾⁽²⁾

(\$ millions)	Before Income Taxes Discounted at				
	0%	5%	10%	15%	20%
Proved					
Developed producing	1,363	1,014	794	651	553
Developed non-producing	4	3	3	3	2
Undeveloped	838	496	304	191	120
Total proved	2,204	1,513	1,102	845	675
Total probable	1,436	799	483	312	211
Total proved plus probable	3,640	2,312	1,585	1,157	886

(\$ millions)	After Income Taxes Discounted at				
	0%	5%	10%	15%	20%
Proved					
Developed producing	1,248	952	759	630	539
Developed non-producing	3	3	3	2	2
Undeveloped	608	355	213	128	75
Total proved	1,858	1,310	974	760	616
Total probable	1,048	576	343	216	143
Total proved plus probable	2,906	1,886	1,316	977	759

Notes:

- (1) Based on escalated prices and costs.
- (2) Figures may not add due to rounding.

Future Development Capital

The table below outlines Ryder Scott's estimate of FDC, which does not include abandonment liabilities, required to bring 1P and 2P reserves on production. Changes in forecast FDC occur annually for a number of reasons including development activities, changes in capital cost estimates and changes in service costs. Actual capital expenditures may differ from FDC.

(\$000)	Proved Reserves	Proved plus Probable Reserves
2018	42,678	47,496
2019	108,881	131,327
2020	86,529	197,571
2021	65,434	129,932
2022	51,825	105,162
Remainder	66,580	187,648
Total Undiscounted	421,927	799,136

Finding, Development and Acquisition Costs

Reserves, Capital Expenditures and Operating Netbacks	2017	2016 ⁽¹⁾	2015
Reserves (Mboe)			
Proved developed producing	52,013	51,220	57,249
Total proved	82,671	75,366	85,930
Proved plus probable	129,356	127,658	152,709
Capital Expenditures (\$000s)			
Exploration and development	57,932	51,445	65,489
Net property acquisitions (dispositions)	(1,698)	(72,954)	4,546
Total capital expenditures	56,234	(21,509)	70,035
Operating Netback (\$/boe)			
Operating netback	21.85	13.67	18.71

Note:

- (1) 2016 reserves reflect the disposition of certain properties (16.5 MMboe of 2P reserves) and a reduction in probable reserves (13.4 MMboe) as a result of an extension to the timeline for the development of the Cactus Lake SAGD project.

FD&A Costs, including FDC	2017	2016	2015
Proved developed producing			
FD&A costs (\$/boe) ⁽¹⁾	6.58	3.53	2.52
FD&A recycle ratio ⁽²⁾	3.3	3.9	7.4
FD&A costs – three-year average (\$/boe) ⁽¹⁾	4.80	14.25	24.57
FD&A recycle ratio – three-year average ⁽²⁾	3.8	1.7	1.3
Total Proved			
FD&A costs (\$/boe) ⁽¹⁾	7.01	25.96	18.20
FD&A recycle ratio ⁽²⁾	3.1	0.5	1.0
FD&A costs – three-year average (\$/boe) ⁽¹⁾	8.66	14.77	26.53
FD&A recycle ratio – three-year average ⁽²⁾	2.1	1.7	1.2
Proved plus Probable			
FD&A costs (\$/boe) ⁽¹⁾	3.54	17.52	(0.55)
FD&A recycle ratio ⁽²⁾	6.2	0.8	(33.8)
FD&A costs – three-year average (\$/boe) ⁽¹⁾	35.13	35.81	18.96
FD&A recycle ratio – three-year average ⁽²⁾	0.5	0.7	1.7

Notes:

- (1) FD&A costs are calculated as the sum of exploration and development capital, acquisition/disposition capital and the change in future development costs for the period divided by the change in total reserves plus production for the period. FD&A costs does not have a standardized meaning – see “Information Regarding Disclosure on Oil and Gas Reserves and Operational Information” below.
- (2) Recycle ratio is calculated as operating netback divided by FD&A costs. Operating netback is calculated as oil and natural gas sales (excluding realized gains and losses on financial derivative contracts) minus blending expenses, royalties, operating expenses and transportation expenses. Recycle ratio does not have a standardized meaning – see “Information Regarding Disclosure on Oil and Gas Reserves and Operational Information” below.

F&D Costs, including FDC	2017	2016	2015
Proved developed producing			
F&D costs (\$/boe) ⁽¹⁾	6.82	9.07	8.32
F&D recycle ratio ⁽²⁾	3.2	1.5	2.2
F&D costs – three-year average (\$/boe) ⁽¹⁾	8.10	12.79	22.96
F&D recycle ratio – three-year average ⁽²⁾	2.2	2.0	1.4
Total Proved			
F&D costs (\$/boe) ⁽¹⁾	7.11	5.91	17.71
F&D recycle ratio ⁽²⁾	3.1	2.3	1.1
F&D costs – three-year average (\$/boe) ⁽¹⁾	9.91	14.09	24.82
F&D recycle ratio – three-year average ⁽²⁾	1.8	1.8	1.3
Proved plus Probable			
F&D costs (\$/boe) ⁽¹⁾⁽³⁾	3.72	54.87 ⁽³⁾	(2.85)
F&D recycle ratio ⁽²⁾⁽³⁾	5.9	0.3	(6.6)
F&D costs (\$/boe) – three-year average ⁽¹⁾	(13.20) ⁽³⁾	9.57 ⁽³⁾	17.98
F&D recycle ratio – three-year average ⁽²⁾	(1.4) ⁽³⁾	2.6 ⁽³⁾	1.8

Notes:

- (1) F&D costs are calculated as the sum of exploration and development capital and the change in future development costs for the period divided by the change in total reserves plus production for the period. F&D costs does not have a standardized meaning – see “Information Regarding Disclosure on Oil and Gas Reserves and Operational Information” below.

- (2) Recycle ratio is calculated as operating netback divided by F&D costs. Operating netback is calculated as oil and natural gas sales (excluding realized gains and losses on financial derivative contracts) minus blending expenses, royalties, operating expenses and transportation expenses. Recycle ratio does not have a standardized meaning – see “Information Regarding Disclosure on Oil and Gas Reserves and Operational Information” below.
- (3) 2016 reserves reflect the reduction of 13.4 MMboe probable reserves as a result of an extension to the timeline for the development of the Cactus Lake SAGD project. Exclusive of this reduction the measures would have been: 2016 F&D costs - \$6.02 per boe, 2016 recycle ratio - 2.3 times, 2016 three-year average F&D costs - \$11.03 per boe, 2016 three-year average recycle ratio - 2.3 times, 2017 three-year average F&D costs - \$4.31 per boe, and 2017 three-year average recycle ratio - 4.2 times.

Reserve Life Index^(1,2)

(years)	2017	2016	2015
Total proved	13.5	11.3	12.3
Proved plus probable	21.2	19.1	21.9

Notes:

- (1) Reserve life index is calculated as reserves divided by annualized fourth quarter production.
- (2) Reserve life index does not have a standardized meaning – see “Information Regarding Disclosure on Oil and Gas Reserves and Operational Information” below.

Forecast Prices in 2017 Reserves Evaluation

The following table summarizes the first ten years of the forecast prices used by Ryder Scott in preparing Cona's estimated reserve volumes and net present values of future net revenues in the Reserves Evaluation.

Year	Oil					Natural Gas	
	US\$/ CDN\$	Cost Escalation (%)	WTI at Cushing (US\$/bbl)	WCS Stream at Hardisty 20.5 API (\$/bbl)	Edmonton MSW 40° API (\$/bbl)	Alberta AECO- C/NIT 30 Day Spot (\$/mmbtu)	Saskatchewan Provincial Average (\$/mmbtu)
2018	0.790	1.00	58.13	52.02	69.12	2.56	2.36
2019	0.798	2.00	59.80	55.54	70.69	2.81	2.61
2020	0.812	2.00	63.35	59.84	73.68	3.22	2.95
2021	0.823	2.00	67.75	63.71	77.91	3.51	3.27
2022	0.834	2.00	70.89	66.11	80.48	3.74	3.50
2023	0.839	2.00	73.36	68.33	82.84	3.88	3.64
2024	0.841	2.00	75.74	70.66	85.35	3.97	3.70
2025	0.843	2.00	77.88	72.78	87.64	4.04	3.76
2026	0.843	2.00	79.66	74.54	89.57	4.13	3.85
2027	0.844	2.00	81.26	76.06	91.28	4.22	3.92
2028+	See Note 2 for additional details						

Notes:

- (1) All prices, cost escalation and exchange rates used by Ryder Scott in the 2017 reserves report were an average of forecast prices and costs published by Ryder Scott, Sproule Associates Ltd., GLJ Petroleum Consultants Ltd. and McDaniel & Associates Consultants Ltd. as at December 31, 2017.
- (2) Cost escalation of 2% per annum until 2036 after which no further escalation.

Wells Drilled

The following table summarizes Cona's 2017 drilling program:

Field	Gross	Net
Cactus Lake	37	37.0
Winter ⁽¹⁾	32	29.0
Luseland	1	1.0
Total	70	67.0

Note:

(1) There were 2.0 net service wells drilled at Winter during 2017.

OPERATIONS AND CORPORATE UPDATE

Production for the year ended December 31, 2017 averaged 17,206 boe/d. Fourth quarter production of 16,739 boe/d was impacted by severe winds and unusually wet weather in southwest Saskatchewan. Volumes recovered to an average of 17,060 boe/d for the month of December. Capital expenditures for 2017 totalled \$57.9 million, which included the drilling of 70 (67.0 net) wells. 2017 development was focused primarily in the Cactus Lake and Winter areas.

On January 16, 2018, Cona announced an asset disposition program. The response has been positive and to date we have closed two transactions. The first transaction was the previously announced sale of a minor property for proceeds of approximately \$7.5 million. The second transaction was an asset exchange with a working interest partner. The asset exchange increased our working interest in the Cona operated Winter property to 100% from an average of 71% (based on December 31, 2017 2P reserves), in exchange for our interest in a non-operated asset. While neutral to current production, the consolidation of our interest across the Winter field provides additional drilling locations, gives Cona more control over the development program and increases production optimization opportunities.

ADVISORIES

Unaudited Financial Information

Certain financial and operating information included in this news release for the quarter and year ended December 31, 2017, such as FD&A costs, F&D costs, recycle ratios, capital expenditures and operating netback are based on unaudited financial results for the year ended December 31, 2017. These estimated amounts may change upon the completion of the audited financial statements for the year ended December 31, 2017 and those changes may be material.

BOE Conversion and Other Advisories

In this news release, natural gas has been converted to boe based on a conversion rate of six thousand cubic feet of natural gas to one barrel (6 mcf : 1 bbl), which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Information Regarding Disclosure on Oil and Gas Reserves and Operational Information

This press release contains F&D costs, FD&A costs, recycle ratios and reserve life indexes, which are all metrics commonly used in the oil and natural gas industry. 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.

F&D costs are calculated as the sum of exploration and development capital plus the change in future development costs for the period divided by the change in total reserves plus production for the period. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total F&D costs related to reserves additions for the year.

FD&A costs are calculated as the sum of development capital plus acquisition capital plus the change in future development costs for the period divided by the change in total reserves plus production for the period. The aggregate of the exploration, development and acquisition costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total FD&A costs related to reserves additions for the year.

F&D recycle ratio is calculated as operating netback per boe divided by finding and development costs per boe.

FD&A recycle ratio is calculated as operating netback per boe divided by finding, development and acquisition costs per boe.

Operating netback is calculated as oil and natural gas sales (excluding realized gains and losses on financial derivative contracts) minus blending expenses, royalties, operating expenses and transportation expenses.

	2017	2016	2015
Oil and natural gas sales (\$000)	368,084	308,754	422,305
Blending expenses (\$000)	(77,753)	(73,804)	(100,885)
Royalties (\$000)	(30,560)	(24,716)	(35,451)
Operating costs (\$000)	(109,098)	(106,542)	(128,265)
Transportation expenses (\$000)	(13,454)	(12,220)	(14,180)
Operating netback (\$000)	137,219	91,472	143,524
Sales volumes (boe/d)	17,211	18,295	21,020
Operating netback (\$/boe)	21.85	13.67	18.71

Reserve life index is calculated as reserves divided by annualized fourth quarter production.

The Company uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's 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.

Cona's oil and natural gas reserves statement for the year ended December 31, 2017, which will include complete disclosure of its oil and natural gas reserves in accordance with NI 51-101, will be contained within Cona's AIF which will be available on or before March 30, 2018 on Cona's website at www.conaresources.com and on SEDAR at www.sedar.com.

Unless otherwise indicated, all currency is in Canadian dollars.

Forward-Looking Statements

This news release contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking statements") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements contain words such as "anticipate", "believe", "plan", "continuous", "estimate", "expect", "may", "will", "project", "should", or similar words suggesting future outcomes.

In addition, statements relating to “reserves” are 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 can be profitably produced in the future.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

With respect to forward-looking statements contained in this news release, management has made assumptions regarding future production levels; future oil and natural gas prices; future operating costs; timing and amount of capital expenditures; the ability to obtain financing on acceptable terms; availability of skilled labour and drilling and related equipment; general economic and financial market conditions; continuation of existing tax and regulatory regimes; and the ability to market oil and natural gas successfully to current and new customers. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that the goals or figures contained in forward-looking statements will not be achieved. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent, general economic, market and business conditions, substantial capital requirements, uncertainties inherent in estimating quantities of reserves and resources, extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time, the need to obtain regulatory approvals on projects before development commences, environmental risks and hazards and the cost of compliance with environmental regulations, aboriginal claims, inherent risks and hazards with operations such as fire, explosion, blowouts, mechanical or pipe failure, cratering, oil spills, vandalism and other dangerous conditions, potential cost overruns, variations in foreign exchange rates, diluent supply shortages, competition for capital, equipment, new leases, pipeline capacity and skilled personnel, credit risks associated with counterparties, the failure of the Company or the holder of licenses, leases and permits to meet requirements of such licenses, leases and permits, reliance on third parties for pipelines and other infrastructure, changes in royalty regimes, failure to accurately estimate decommissioning costs, inaccurate estimates and assumptions by management, effectiveness of internal controls, the potential lack of available drilling equipment and other restrictions, failure to obtain or keep key personnel, title deficiencies with the Company's assets, geo-political risks, risks that the Company does not have adequate insurance coverage, risk of litigation and risks arising from future acquisition activities. The foregoing risks and other risks are described in more detail in the Company's annual information form for the year ended December 31, 2016. Readers are cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved may vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there is no representation by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Furthermore, the forward-looking statements contained in this news release are made as of the date hereof, and the Company does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

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