NEWS RELEASE

CONTINENTAL RESOURCES REPORTS FOURTH QUARTER AND FULL-YEAR 2017 RESULTS

$841.9 Million (MM) for 4Q 2017 Net Income, or $2.25 per Diluted Share; Including $128.2 MM from Operations and $713.7 MM Benefit from Federal Tax Reform

286,985 Barrels of Oil Equivalent (Boe) per Day (59% Oil) Average for 4Q 2017 Production, up 37% over 4Q 2016; Oil Production up 44% over 4Q 2016

242,637 Boe per Day (57% Oil) Average Full-Year 2017 Production, up 12% over 2016

$261 MM Debt Reduction in 4Q 2017; $95 MM Debt Reduction in January 2018

1.33 Billion Boe Year-End 2017 Proved Reserves, Up 4% over Year-End 2016

Bakken Continues to Set Company Records:

- **39 gross operated wells brought online in 4Q 2017 with 24-hour initial production (IP) average of 2,180 Boe per well**
- **Five 4Q 2017 wells are Company record Bakken producers, flowing an average of 2,230 Boe per day (80% oil) during first 30 days**
- **4Q 2017 Bakken production up 58% over 4Q 2016, reaching all time high**

STACK Meramec:

- **Company announces preliminary model to maximize net present value discounted at 10% (PV-10) for unit development in over-pressured oil window**

SCOOP Springer:

- **Density testing transitions to unit development with five rigs in 2018**
- **Type curve uplifted 28% to 1,200 MBoe (~75% oil) for a 7,500-foot unit well**
- **Unit rate of return 175% assuming four wells per unit to maximize PV-10**

Oklahoma City, February 21, 2018 – Continental Resources, Inc. (NYSE: CLR) (the Company) today announced fourth quarter and full-year 2017 operating and financial results. Continental reported net income of $841.9 million, or $2.25 per diluted share, for the quarter ended

December 31, 2017. Of total net income, $128.2 million was from operations and $713.7 million was from federal tax reform. The Company reported full-year net income of $789.4 million, or $2.11 per diluted share, with $75.7 million from operations and $713.7 million from federal tax reform.

The Company's net income includes certain items typically excluded by the investment community in published estimates, the result of which is referred to as "adjusted net income." In fourth quarter 2017, these typically excluded items in aggregate represented $688.2 million, or $1.84 per diluted share, of Continental's reported net income. Adjusted net income for the fourth quarter was $153.7 million, or $0.41 per diluted share. For full-year 2017, these typically excluded items in aggregate represented $598.6 million, or $1.60 per diluted share. Adjusted net income for full-year 2017 was $190.8 million, or $0.51 per diluted share.

Net cash provided by operating activities for fourth quarter 2017 was $731.1 million, and for full-year 2017 it was $2.1 billion. EBITDAX for fourth quarter 2017 was $837.9 million, contributing to full-year 2017 EBITDAX of $2.4 billion. Definitions and reconciliations of adjusted net income (loss), adjusted net income (loss) per share and EBITDAX to the most directly comparable U.S. generally accepted accounting principles (GAAP) financial measures can be found in the supporting tables at the conclusion of this press release.

"Continental's fourth quarter performance was a fitting completion to a standout year," said Harold Hamm, Chairman and Chief Executive Officer. "As we made clear in our 2018 guidance announcement, we expect even stronger performance in 2018 with both significant production growth and robust free cash flow."

Full-Year 2017 Production Increases 12% Over 2016

Fourth quarter 2017 net production totaled 26.4 million Boe, or 286,985 Boe per day, up 18% from third quarter 2017, with oil production up 20% to 168,066 barrels of oil (Bo) per day. Compared to fourth quarter 2016, Continental increased production 37%, with oil production up 44%.

Total net production for fourth quarter 2017 included 168,066 Bo per day (59% of production) and 713.5 million cubic feet (MMcf) of natural gas per day (41% of production). Full-year 2017 production averaged 242,637 Boe per day.

First quarter 2018 production is estimated to be between 285,000 and 290,000 Boe per day.

The following table provides the Company's average daily production by region for the periods presented.

Boe per day	4Q 2017	3Q 2017	4Q 2016	FY 2017	FY 2016
North Region:					
North Dakota Bakken	158,640	129,582	96,035	125,577	109,686
Montana Bakken	6,958	7,269	8,489	7,415	9,514
Red River Units	9,497	9,536	10,140	9,748	10,745
Other	468	449	4,109	434	1,665
South Region:					
SCOOP	62,242	57,283	63,490	60,693	65,062
STACK	47,914	35,619	24,426	36,220	16,983
Arkoma(1)	11	1,722	1,929	1,315	1,915
Other	1,255	1,328	1,243	1,235	1,342
Total	286,985	242,788	209,861	242,637	216,912

(1) Producing properties comprising approximately 1,700 Boe per day of the Company's Arkoma production were sold in September 2017.

Bakken Continues to Deliver Record Results

Continental's Bakken net production reached an all-time high in the fourth quarter averaging 165,598 Boe per day, up 58% over the fourth quarter 2016. The Company completed 97 gross (37 net) operated and non-operated Bakken wells with first production during fourth quarter 2017. Thirty-nine of the fourth quarter wells were operated by the Company with an average 24-hour IP of 2,180 Boe per day. The Company completed a total 350 gross (134 net) operated and non-operated Bakken wells with first production for full-year 2017. The Company plans to keep an average of six operated drilling rigs in the play during 2018.

Five of the fourth quarter operated wells produced the highest 30-day rates ever recorded from the Company's operated Bakken wells, averaging 2,230 Boe per day. This included the Monroe 6-2H that produced at an average 30-day rate of 2,869 Boe, which was the best 30-day rate ever achieved by the Company from a Bakken well. All of the wells were completed using the Company's optimized completion designs with various combinations of larger proppant loads, tighter stage spacing and diverter technology, along with accelerated flow backs and high-capacity lift.

From late 2016 through fourth quarter 2017, the Company has brought on 134 optimized Bakken wells in Dunn, McKenzie, Mountrail and Williams counties. Average production per well is slightly outperforming the Company's updated 1,100 MBoe Bakken type curve announced in August 2017. The type curve delivers a 125% rate of return at $60 per barrel WTI (WTI) and $3.00 per Mcf Henry Hub (HH). This more than doubles the rate of return expected from the Company's previous type curve.

“Continental’s returns from the Bakken compete head to head with the best oil plays in the U.S. today, driven by our optimized completions, lower production expense and the $4.50 per Bo improvement in oil differentials since 2015,” said Jack Stark, President. “On top of that, Bakken production is 80% crude oil.”

The Company exited 2017 with a drilled-well inventory of 165 gross operated wells in the Bakken, including 52 gross operated wells with stimulation complete or in progress, but which did not have first sales in 2017.

STACK: Density Tests Defining Unit Development

Continental’s STACK net production averaged 47,914 Boe per day in fourth quarter 2017, a 96% increase over fourth quarter 2016. A total of 63 gross (23 net) operated and non-operated STACK wells with first production were completed during the quarter, and 158 gross (52 net) operated and non-operated wells were completed with first production for the full year. The Company plans to keep an average of eight operated drilling rigs in the play during 2018, with four to six targeting the Woodford and Meramec formations as part of the joint development agreement with SK E&S.

The Company is introducing its preliminary economic model for unit development in the STACK Meramec over-pressured oil window. The unit economic model is based on the results of six full-unit density tests the Company has completed with three-to-five wells per zone. Initial results indicate that four wells per zone on average will deliver the maximum PV-10 from a single Meramec reservoir in a unit. The Company’s unit economic model includes a total of eight wells with four wells in two Meramec reservoirs given the Company expects to target two Meramec reservoirs on average underlying its acreage in the over-pressured oil window. Combined these eight wells are projected to recover an estimated 9.6 million Boe (MMBoe) and deliver a PV-10 of approximately $87 million with a rate of return of 96%, assuming a completed well cost of $9.5 million for a 9,800-foot lateral well at $60 WTI and $3 HH. In addition, up to four more wells can be expected to be completed in the underlying Woodford formation.

The unit economic model includes results from the Verona and Gillilan density tests that were completed during the fourth quarter. These two units adjoin each other and were strategically selected to compare eight and 10 well density development. The Verona unit included four wells in the Upper and four wells in the Lower Meramec. The eight wells had a combined unit 24-hour IP of 18,205 Boe per day, averaging 2,281 Boe per day per well, and 68% of the production was crude oil. Results for the Verona were in-line with Company expectations. The Gillilan unit included five wells in the Upper and five wells in the Lower Meramec. The 10 wells had a combined unit 24-hour IP of 11,024 Boe per day, averaging 1,102 Boe per day per well, and 64% of the production was crude oil. Early performance from the Gillilan wells indicates the unit was over-drilled with ten wells and further supports the Company’s eight-well model.

During the fourth quarter the Company also completed its first density test in the STACK Meramec over-pressured condensate window. The Angus Trust density test involved only half of the unit with three wells drilled in the Upper Meramec and three wells drilled in the Lower

Meramec. This is the tightest well spacing Continental has tested to date, which is the equivalent of six wells per zone or 12 wells in the unit. The half-unit 24-hour IP for the Angus Trust test was 15,955 Boe per day and 39% of the production was crude oil. Average IP per well was 2,659 Boe per day. Early performance indicates the maximum PV-10 from a unit can be achieved with fewer than 12 Meramec wells per unit in the over-pressured condensate window. To further evaluate the proper well density, the Company has begun drilling a second density test at the Simba unit located one mile west of the Angus Trust unit. The Simba will be a six-well, full-unit test with three wells in Upper and three wells in the Lower Meramec.

SCOOP

In fourth quarter 2017, SCOOP net production averaged 62,242 Boe per day (23% oil), or 22% of the Company's total production in fourth quarter. A total of 12 gross (1 net) operated and non-operated SCOOP wells were completed with first production during the quarter, and 71 gross (16 net) operated and non-operated wells were completed with first production for the full year. In 2018, the Company plans to average seven operated rigs in the play.

SCOOP Springer: Beginning Full-Field Development; Type Curve EUR Uplifted 28% for Unit Well

Continental has concluded its initial Springer density testing program and is beginning full-field development with five rigs dedicated to the Springer in 2018. The Company has completed three density pilots that tested four, five and six well configurations in the Springer reservoir. Results indicate that on average, four wells should deliver the maximum PV-10 from the Springer reservoir on a unit basis. A Springer unit well is projected to recover 1,200 MBoe at a completed well cost of $9.5 million for a 7,500-foot lateral. This is a 28% uplift in EUR from the Company's legacy 940 MBoe type curve for a 4,500-foot standalone well. The Company's unit economic model projects that a four-well Springer unit will produce a combined 4.8 MMBoe over the life of the wells and generate a PV-10 of approximately $68 million and a rate of return of 175% assuming $60 WTI and $3 HH. This adds approximately $44 million to the PV-10 of a Springer unit compared to a standalone well at $60 WTI and $3 HH.

"Longer laterals and optimized completions in the Springer have doubled our type curve rate of return with $4.0 million incremental first-year gross cash flow per well," said Gary Gould, SVP of Production and Resource Development. "Approximately 20% of Continental's operated drilling and completion capital budget will be focused on the Springer oil play in 2018."

During the fourth quarter, the Company completed its third density pilot with the completion of the six-well Celesta density unit. The six wells flowed at a combined peak 24-hour rate of 6,014 Boe (81% oil). The five new wells produced at an average 24-hour peak production rate of 939 Boe per day. The average lateral length was 9,400 feet for the six wells. Early performance of the Celesta unit wells indicates the maximum PV-10 from a unit can be achieved with fewer than six wells and supports the Company's four-well economic model for a Springer unit.

“We are eager to begin development of this prolific oil reservoir,” said Mr. Stark. “Timing is right to take advantage of improved crude prices and our optimized completion technology.”

SCOOP Woodford Oil Type Curve Increased Again

The Company announced it has increased the EUR for two-mile lateral wells drilled in the SCOOP Woodford oil window by approximately 13% to 1,520 MBoe per well, with 60% of production being crude oil. The increase in EUR was based on the results of 32 optimized completions conducted over the past several years in the SCOOP Woodford oil window and assumes an average 9,800-foot lateral well. At a targeted completed well cost of $12.7 million per well, this yields a 55% rate of return at $60 WTI and $3.00 HH.

The Company recently completed the Pyle 1-36-25XH in the SCOOP Woodford oil window. The Pyle flowed at a 24-hour IP of 1,812 Boe with 81% of the production being crude oil from a 9,800-foot lateral.

2017 Proved Reserves: Standardized Measure and PV-10 (non-GAAP) Up 90% and 78%, respectively, over Year-End 2016

The Company announced proved reserves of 1.33 billion Boe at December 31, 2017, a 4% increase compared with year-end 2016 proved reserves. The 2017 average SEC oil price was $51.34 per barrel, and the 2017 average SEC natural gas price was $2.98 per MMBtu.

At December 31, 2017, Continental had a Standardized Measure of discounted future net cash flows of $10.47 billion. Continental's 2017 proved reserves had a PV-10 of $11.83 billion, up 78% year-over-year. PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial metric, because it does not include the effects of discounted income taxes on future net revenues of approximately $1.36 billion. Continental and others in the crude oil and natural gas industry use PV-10 to compare the relative size and value of proved reserves without regard to specific income tax characteristics.

Year-end 2017 proved reserves were 48% crude oil, 89% operated by the Company, and approximately 45% were classified as proved developed producing (PDP).

The Bakken accounted for 635.5 MMBoe, or 48% of Continental's year-end 2017 proved reserves. The SCOOP Woodford and SCOOP Springer plays accounted for 491.8 MMBoe, or 37% of Continental’s year-end 2017 proved reserves. The STACK accounted for 167.4 MMBoe, or 13% of Continental’s year-end 2017 proved reserves.

The Company had a total of 1,783 gross (976 net) proved undeveloped (PUD) locations at year-end 2017, with the Bakken accounting for 1,252 gross (656 net) PUD locations. SCOOP accounted for an additional 336 gross (230 net) PUD locations, while STACK accounted for 195 gross (90 net) PUD locations at year-end 2017.

Financial Update: 4Q 2017 Annualized Net-Debt-to-EBITDAX Ratio below 1.9x

“We were very pleased to finish 2017 in line or better than our guidance,” said John Hart, Chief Financial Officer. “Fourth quarter 2017 was excellent from an operations standpoint. Production expense per Boe was down 17% from third quarter 2017, and all other cash operating costs were within budget. This speaks directly to the performance of our operating teams and the premier quality of our assets.

“By year end, long-term debt was $6.35 billion, and our fourth quarter annualized net-debt-to-EBITDAX ratio was 1.88x. We fully expect this to continue to trend down through 2018 as we pay down debt with excess cash flow, sell non-core assets, grow production and reap the benefit of higher commodity prices.”

Net debt and EBITDAX are non-GAAP measures. Definitions and reconciliations of these measures to the most directly comparable U.S. GAAP financial measure are provided subsequently under the header “Non-GAAP Financial Measures.”

In fourth quarter 2017, Continental’s average realized sales price excluding the effects of derivative positions was $51.16 per barrel of oil and $3.30 per Mcf of gas, or $38.27 per Boe. Based on realizations without the effect of derivatives, the Company’s fourth quarter 2017 oil differential was $4.23 per barrel below the NYMEX daily average for the period. The realized wellhead natural gas price for the quarter was on average $0.37 per Mcf above the average NYMEX Henry Hub benchmark price.

The corporate oil differential has improved by $2.86 per Bo from first quarter 2017, and the corporate gas differential has improved by $0.66 per Mcf. These trends reflect improved takeaway capacity in both the Bakken and Oklahoma as well as improving natural gas liquids pricing. The Company is expecting crude oil differentials to continue to improve in 2018 due to a recent renegotiation of an existing transportation contract at more favorable rates and terms, which should impact the Company’s cash flow growth considerably.

Production expense per Boe was $3.17 for fourth quarter 2017, down a remarkable 17% compared with $3.82 per Boe for third quarter 2017. This improvement was primarily driven by reduced water handling and disposal costs from increased recycling activities in Oklahoma, reduced workover activity and the increase in production quarter over quarter. Other select operating costs and expenses for fourth quarter 2017 included production taxes of 7.3% of oil and natural gas sales; DD&A of $17.93 per Boe; and total G&A of $2.30 per Boe.

As of December 31, 2017, Continental’s balance sheet included $43.9 million in cash and cash equivalents and $188 million of borrowings against the Company’s revolving credit facility. At year-end 2017 Continental’s long-term debt was $6.35 billion, down $261 million from September 30, 2017. As of January 31, 2018 Continental’s long-term debt was down another $95 million to $6.26 billion.

Continental’s 2018 guidance remains as announced on February 15, 2018 and can be found at the conclusion of this press release.

The following table provides the Company’s production results, average sales prices, per-unit operating costs, results of operations and certain non-GAAP financial measures for the periods presented. Average sales prices exclude any effect of derivative transactions. Per-unit expenses have been calculated using sales volumes.

	Three months ended December 31,		Year ended December 31,	
	2017	2016	2017	2016
Average daily production:				
Crude oil (Bbl per day)	168,066	116,486	138,455	128,005
Natural gas (Mcf per day)	713,518	560,251	625,093	533,442
Crude oil equivalents (Boe per day)	286,985	209,861	242,637	216,912
Average sales prices, excluding effect from derivatives:				
Crude oil ($/Bbl)	$51.16	$42.23	$45.70	$35.51
Natural gas ($/Mcf)	$3.30	$2.70	$2.93	$1.87
Crude oil equivalents ($/Boe)	$38.27	$30.64	$33.65	$25.55
Production expenses ($/Boe)	$3.17	$3.60	$3.66	$3.65
Production taxes (% of oil and gas revenues)	7.3%	6.4%	7.0%	7.0%
DD&A ($/Boe)	$17.93	$20.11	$18.89	$21.54
Total general and administrative expenses ($/Boe) (1)	$2.30	$2.93	$2.16	$2.14
Net income (loss) (in thousands) (2)	$841,914	$27,670	$789,447	($399,679)
Diluted net income (loss) per share (2)	$2.25	$0.07	$2.11	($1.08)
Adjusted net income (loss) (non-GAAP) (in thousands) (3)	$153,660	($27,416)	$190,803	($326,648)
Adjusted diluted net income (loss) per share (non-GAAP) (3)	$0.41	($0.07)	$0.51	($0.88)
Net cash provided by operating activities	$731,125	$262,031	$2,079,106	$1,125,919
EBITDAX (non-GAAP) (in thousands) (3)	$837,887	$652,382	$2,363,617	$1,881,889

(1) Total general and administrative expense is comprised of cash general and administrative expense and non-cash equity compensation expense. Cash general and administrative expense per Boe was $1.80, $2.21, $1.64, and $1.53 for 4Q 2017, 4Q 2016, FY 2017 and FY 2016, respectively. Non-cash equity compensation expense per Boe was $0.50, $0.72, $0.52, and $0.61 for 4Q 2017, 4Q 2016, FY 2017 and FY 2016, respectively.

(2) In December 2017, the Tax Cuts and Jobs Act was signed into law, which among other things reduces the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018. In accordance with U.S. GAAP, the Company remeasured its deferred income tax assets and liabilities as of December 31, 2017 to reflect the reduced tax rate, which resulted in a one-time increase in net income of approximately $713.7 million ($1.91 per diluted share) for the three and twelve months ended December 31, 2017.

(3) Adjusted net income (loss), adjusted diluted net income (loss) per share, and EBITDAX represent non-GAAP financial measures. These measures should not be considered as an alternative to, or more meaningful than, net income (loss), diluted net income (loss) per share, or net cash provided by operating activities as determined in accordance with U.S. GAAP. Further information about these non-GAAP financial measures as well as reconciliations of adjusted net income (loss), adjusted diluted net income (loss) per share, and EBITDAX to the most directly comparable U.S. GAAP financial measures are provided subsequently under the header *Non-GAAP Financial Measures*.

Fourth Quarter and Full-Year Earnings Conference Call

Continental plans to host a conference call to discuss fourth quarter and full-year results on Thursday, February 22, 2018, at 12 p.m. ET (11 a.m. CT). Those wishing to listen to the conference call may do so via the Company's website at www.CLR.com or by phone:

Time and date:	12 p.m. ET, Thursday, February 22, 2018
Dial in:	844-309-6572
Intl. dial in:	484-747-6921
Pass code:	9287808

A replay of the call will be available for 14 days on the Company’s website or by dialing:

Replay number:	855-859-2056 or 404-537-3406
Intl. replay:	800-585-8367
Pass code:	9287808

Continental plans to publish a fourth quarter and full-year 2017 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on February 22, 2018.

Upcoming Conferences

Members of Continental's management team plan to participate in the following investment conferences:

Feb 28–Mar 2, 2018	18th Annual Simmons/Piper Jaffray Energy Conference, Las Vegas
March 13, 2018	Evercore ISI Energy/Power Summit 2018, Houston
March 26-27, 2018	Scotia Howard Weil 46th Annual Energy Conference, New Orleans

About Continental Resources

Continental Resources (NYSE: CLR) is a top 10 independent oil producer in the U.S. Lower 48 and a leader in America's energy renaissance. Based in Oklahoma City, Continental is the largest leaseholder and the largest producer in the nation's premier oil field, the Bakken play of North Dakota and Montana. The Company also has significant positions in Oklahoma, including its SCOOP Woodford and SCOOP Springer discoveries and the STACK plays. With a focus on the exploration and production of oil, Continental has unlocked the technology and resources vital to American energy independence and our nation's leadership in the new world oil market. In 2018, the Company will celebrate 51 years of operations. For more information, please visit www.CLR.com.

Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

This press release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements included in this press release other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company's business and statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows are forward-looking statements. When used in this press release, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "plan," "continue," "potential," "guidance," "strategy," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. The risks and uncertainties include, but are not limited to, commodity price volatility; the geographic concentration of our operations; financial market and economic volatility; the inability to access needed capital; the risks and potential liabilities inherent in crude oil and natural gas drilling and production and the availability of insurance to cover any losses resulting therefrom; difficulties in estimating proved reserves and other reserves-based measures; declines in the values of our crude oil and natural gas properties resulting in impairment charges; our ability to replace proved reserves and sustain production; the availability or cost of equipment and oilfield services; leasehold terms expiring on undeveloped acreage before production can be established; our ability to project future production, achieve targeted results in drilling and well operations and predict the amount and timing of development expenditures; the availability and cost of transportation, processing and refining facilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing; increased market and industry competition, including from alternative fuels and other energy sources; and the other risks described under Part I, Item 1A. Risk Factors and elsewhere in the Company's Annual Report on Form 10-K for the year ended December 31, 2016, and once filed, for the year ended December 31, 2017, registration statements and other reports filed from time to time with the SEC, and other announcements the Company makes from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this press release occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. Except as otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this report, or otherwise.

Readers are cautioned that initial production rates are subject to decline over time and should not be regarded as reflective of sustained production levels. In particular, production from horizontal drilling in shale oil and natural gas resource plays and tight natural gas plays that are stimulated with extensive pressure fracturing are typically characterized by significant early declines in production rates.

We use the term "EUR" or "estimated ultimate recovery" to describe potentially recoverable oil and natural gas hydrocarbon quantities. We include these estimates to demonstrate what we believe to be the potential for future drilling and production on our properties. These estimates are by their nature much more speculative than estimates of proved reserves and require substantial capital spending to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from our properties will differ substantially. EUR data included herein remain subject to change as more well data is analyzed.

Investor Contact:
J. Warren Henry
Vice President, Investor Relations & Research
405-234-9127
Warren.Henry@CLR.com

Alyson L. Gilbert
Manager, Investor Relations
405-774-5814
Alyson.Gilbert@CLR.com

Media Contact:
Kristin Thomas
Senior Vice President, Public Relations
405-234-9480
Kristin.Thomas@CLR.com

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Income (Loss)

	Three months ended December 31,		Year ended December 31,	
	2017	2016	2017	2016
	In thousands, except per share data			
Revenues:				
Crude oil and natural gas sales	$ 1,017,750	$ 591,764	$ 2,982,966	$ 2,026,958
Gain (loss) on crude oil and natural gas derivatives, net	8,165	(47,382)	91,647	(71,859)
Crude oil and natural gas service operations	21,257	5,307	46,215	25,174
Total revenues	1,047,172	549,689	3,120,828	1,980,273
Operating costs and expenses:				
Production expenses	84,371	69,544	324,214	289,289
Production taxes	73,816	38,172	208,278	142,388
Exploration expenses	2,802	8,246	12,393	16,972
Crude oil and natural gas service operations	6,216	2,162	16,880	11,386
Depreciation, depletion, amortization and accretion	476,732	388,321	1,674,901	1,708,744
Property impairments	27,552	34,564	237,370	237,292
General and administrative expenses	61,294	56,537	191,706	169,580
Litigation settlement	59,600	-	59,600	-
Net gain on sale of assets and other	(54,679)	(203,156)	(53,915)	(307,844)
Total operating costs and expenses	737,704	394,390	2,671,427	2,267,807
Income (loss) from operations	309,468	155,299	449,401	(287,534)
Other income (expense):				
Interest expense	(75,823)	(75,613)	(294,495)	(320,562)
Loss on extinguishment of debt	(554)	(26,055)	(554)	(26,055)
Other	506	517	1,715	1,697
	(75,871)	(101,151)	(293,334)	(344,920)
Income (loss) before income taxes	233,597	54,148	156,067	(632,454)
(Provision) benefit for income taxes	608,317	(26,478)	633,380	232,775
Net income (loss)	$ 841,914	$ 27,670	$ 789,447	$ (399,679)
Basic net income (loss) per share	$ 2.27	$ 0.07	$ 2.13	$ (1.08)
Diluted net income (loss) per share	$ 2.25	$ 0.07	$ 2.11	$ (1.08)

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2017	December 31, 2016
Assets	*In thousands*	
Current assets	$ 1,251,725	$ 913,233
Net property and equipment [(1)]	12,933,789	12,881,227
Other noncurrent assets	14,137	17,316
Total assets	$ 14,199,651	$ 13,811,776
Liabilities and shareholders' equity		
Current liabilities	$ 1,330,242	$ 932,393
Long-term debt, net of current portion	6,351,405	6,577,697
Other noncurrent liabilities	1,386,801	1,999,690
Total shareholders' equity	5,131,203	4,301,996
Total liabilities and shareholders' equity	$ 14,199,651	$ 13,811,776

(1) Balance is net of accumulated depreciation, depletion and amortization of $9.08 billion and $7.65 billion as of December 31, 2017 and December 31, 2016, respectively.

Continental Resources, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Three months ended December 31,		Year ended December 31,	
In thousands	2017	2016	2017	2016
Net income (loss)	$ 841,914	$ 27,670	$ 789,447	$ (399,679)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash expenses	(70,395)	369,093	1,288,244	1,687,814
Changes in assets and liabilities	(40,394)	(134,732)	1,415	(162,216)
Net cash provided by operating activities	731,125	262,031	2,079,106	1,125,919
Net cash (used in) provided by investing activities	(434,591)	17,256	(1,808,845)	(532,965)
Net cash used in financing activities	(263,395)	(282,132)	(243,034)	(587,773)
Effect of exchange rate changes on cash	(2)	(8)	32	(1)
Net change in cash and cash equivalents	33,137	(2,853)	27,259	5,180
Cash and cash equivalents at beginning of period	10,765	19,496	16,643	11,463
Cash and cash equivalents at end of period	$ 43,902	$ 16,643	$ 43,902	$ 16,643

Non-GAAP Financial Measures

PV-10

The Company's PV-10 value, a non-GAAP financial measure, is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2017, the Company's PV-10 totaled approximately $11.83 billion. The Standardized Measure of discounted future net cash flows was approximately $10.47 billion at December 31, 2017, representing a $1.36 billion difference from PV-10 due to the effect of deducting estimated future income taxes in arriving at the Standardized Measure. The Company believes the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of the Company's proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Company's crude oil and natural gas properties.

Net debt

Net debt is a non-GAAP measure. We define net debt as total debt less cash and cash equivalents as determined under U.S. GAAP. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. We believe this metric is useful to analysts and investors in determining the Company's leverage position since the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt. At December 31, 2017, the Company's net debt amounted to $6.31 billion, representing total debt of $6.35 billion less cash and cash equivalents of $0.04 billion.

EBITDAX

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. Further, we believe EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income (loss) and operating cash flows in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) or operating cash flows as determined in accordance with U.S. GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation of our net income (loss) to EBITDAX for the periods presented.

	Three months ended December 31,		Year ended December 31,	
In thousands	2017	2016	2017	2016
Net income (loss)	$ 841,914	$ 27,670	$ 789,447	$ (399,679)
Interest expense	75,823	75,613	294,495	320,562
Provision (benefit) for income taxes	(608,317)	26,478	(633,380)	(232,775)
Depreciation, depletion, amortization and accretion	476,732	388,321	1,674,901	1,708,744
Property impairments	27,552	34,564	237,370	237,292
Exploration expenses	2,802	8,246	12,393	16,972
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	(8,417)	45,331	(90,432)	67,099
Total cash received on derivatives, net	15,867	6,281	32,401	89,522
Non-cash (gain) loss on derivatives, net	7,450	51,612	(58,031)	156,621
Non-cash equity compensation	13,377	13,823	45,868	48,097
Loss on extinguishment of debt	554	26,055	554	26,055
EBITDAX (non-GAAP)	$ 837,887	$ 652,382	$ 2,363,617	$ 1,881,889

The following table provides a reconciliation of our net cash provided by operating activities to EBITDAX for the periods presented.

	Three months ended December 31,		Year ended December 31,	
In thousands	2017	2016	2017	2016
Net cash provided by operating activities	$ 731,125	$ 262,031	$ 2,079,106	$ 1,125,919
Current income tax benefit	(7,781)	(22,941)	(7,781)	(22,939)
Interest expense	75,823	75,613	294,495	320,562
Exploration expenses, excluding dry hole costs	2,783	3,613	12,217	12,106
Litigation settlement	(59,600)	-	(59,600)	-
Gain on sale of assets, net	54,420	201,315	55,124	304,489
Tax deficiency from stock-based compensation	-	(368)	-	(9,828)
Other, net	723	(1,613)	(8,529)	(10,636)
Changes in assets and liabilities	40,394	134,732	(1,415)	162,216
EBITDAX (non-GAAP)	$ 837,887	$ 652,382	$ 2,363,617	$ 1,881,889

Adjusted earnings and adjusted earnings per share

Our presentation of adjusted earnings and adjusted earnings per share that exclude the effect of certain items are non-GAAP financial measures. Adjusted earnings and adjusted earnings per share represent earnings and diluted earnings per share determined under U.S. GAAP without regard to non-cash gains and losses on derivative instruments, property impairments, losses on certain litigation settlements, gains and losses on asset sales, losses on extinguishment of debt and the impact of U.S. tax reform legislation. Management believes these measures provide useful information to analysts and investors for analysis of our operating results. In addition, management believes these measures are used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis without regard to an entity's specific derivative portfolio, impairment methodologies, and property dispositions. Adjusted earnings and adjusted earnings per share should not be considered in isolation or as a substitute for earnings or diluted earnings per share as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies. The following tables reconcile earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

	Three months ended December 31,			
	2017		2016	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net income (GAAP)	$ 841,914	$ 2.25	$ 27,670	$ 0.07
Adjustments:				
Non-cash loss on derivatives	7,450		51,612	
Property impairments	27,552		34,564	
Litigation settlement	59,600		-	
Gain on sale of assets	(54,420)		(201,315)	
Loss on extinguishment of debt	554		26,055	
Total tax effect of adjustments (1)	(15,335)		33,998	
Tax benefit from US tax reform legislation	(713,655)		-	
Total adjustments, net of tax	(688,254)	(1.84)	(55,086)	(0.14)
Adjusted net income (loss) (non-GAAP)	$ 153,660	$ 0.41	$ (27,416)	$ (0.07)
Weighted average diluted shares outstanding	373,764		370,539	
Adjusted diluted net income (loss) per share (non-GAAP)	$ 0.41		$ (0.07)	

	Year ended December 31,			
	2017		2016	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net income (loss) (GAAP)	$ 789,447	$ 2.11	$ (399,679)	$ (1.08)
Adjustments:				
Non-cash (gain) loss on derivatives	(58,031)		156,621	
Property impairments	237,370		237,292	
Litigation settlement	59,600		-	
Gain on sale of assets	(55,124)		(304,489)	
Loss on extinguishment of debt	554		26,055	
Total tax effect of adjustments (1)	(69,358)		(42,448)	
Tax benefit from US tax reform legislation	(713,655)		-	
Total adjustments, net of tax	(598,644)	(1.60)	73,031	0.20
Adjusted net income (loss) (non-GAAP)	$ 190,803	$ 0.51	$ (326,648)	$ (0.88)
Weighted average diluted shares outstanding	373,768		370,380	
Adjusted diluted net income (loss) per share (non-GAAP)	$ 0.51		$ (0.88)	

(1) Computed by applying a combined federal and state statutory tax rate of 38% in effect for 2017 and 2016 to the pre-tax amount of adjustments associated with our operations in the United States other than the tax benefit adjustment related to US tax reform legislation.

Cash general and administrative expenses per Boe

Our presentation of cash general and administrative ("G&A") expenses per Boe is a non-GAAP measure. We define cash G&A per Boe as total G&A determined in accordance with U.S. GAAP less non-cash equity compensation expenses, expressed on a per-Boe basis. We report and provide guidance on cash G&A per Boe because we believe this measure is commonly used by management, analysts and investors as an indicator of cost management and operating efficiency on a comparable basis from period to period. In addition, management believes cash G&A per Boe is used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis of G&A spend without regard to stock-based compensation programs which can vary substantially from company to company. Cash G&A per Boe should not be considered as an alternative to, or more meaningful than, total G&A per Boe as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies.

Free cash flow

Our presentation of free cash flow is a non-GAAP measure. We define free cash flow as cash flows from operations before changes in working capital items less capital expenditures excluding acquisitions and divestitures. Free cash flow is not a measure of net income (loss) or cash flows as determined by U.S. GAAP. Management believes that these measures are useful to management and investors as a measure of a company's ability to internally fund its capital expenditures and to service or incur additional debt. These measures eliminate the impact of certain items that management does not consider to be indicative of the Company's performance from period to period. From time to time the Company provides forward-looking free cash flow estimates; however, the Company is unable to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. The reconciling items in future periods could be significant.

Continental Resources, Inc.
2018 Guidance
As of February 21, 2018

	2018
Full year average production	285,000 to 300,000 Boe per day
Exit rate average production	305,000 to 315,000 Boe per day
Capital expenditures (non-acquisition)	$2.3 billion
Operating Expenses:	
Production expense per Boe	$3.00 to $3.50
Production tax (% of oil & gas revenue)	7.6% to 8.0%
Cash G&A expense per Boe(1)	$1.25 to $1.75
Non-cash equity compensation per Boe	$0.45 to $0.55
DD&A per Boe	$17.00 to $19.00
Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	($3.50) to ($4.50)
Henry Hub natural gas (per Mcf)	$0.00 to +$0.50

(1) Cash G&A is a non-GAAP measure and excludes the range of values shown for non-cash equity compensation per Boe in the item appearing immediately below. Guidance for total G&A (cash and non-cash) is an expected range of $1.70 to $2.30 per Boe.