NEWS RELEASE

CONTINENTAL RESOURCES REPORTS SECOND QUARTER 2017 RESULTS AND UPDATES FULL-YEAR GUIDANCE

Company Raises 2017 Production Guidance and Lowers Costs While Targeting Cash Neutrality for the Year:

- **Exit rate raised to 260,000 to 275,000 barrels of oil equivalent (Boe) per day, up 24% to 31% over 4Q 2016**
- **Annual production raised to 230,000 to 240,000 Boe per day**
- **Oil differential improved by $1.00 per barrel and operating costs lowered**
- **Capital expenditures adjusted to a range of $1.75 billion to $1.95 billion, targeting cash neutrality at $45 to $51 WTI**

Company Delivers Solid Second Quarter Production and Cost Performance:

- **Production averaged 226,213 Boe per day, up 6% from 1Q 2017**
- **Oil differential dropped 11% to $6.31 per barrel from $7.09 per barrel in 1Q 2017**
- **Total G&A declined to $1.89 per Boe, compared with $2.45 per Boe in 1Q 2017**

Optimized Completions Increase Both Estimated Ultimate Recoveries (EUR) and Rates of Return (ROR):

- **Bakken ROR uplifted to 82%, based on new 1,100 MBoe type curve EUR**
- **STACK Condensate type curve announced at 80% ROR, based on 2,400 MBoe EUR**
- **SCOOP Springer Cash 1-26H well yields over 100% ROR, 25% higher EUR**

Company Announces New Record STACK Well in Condensate Window of the Play

Company Agrees to Sell Non-Strategic Leasehold and Property for $147.5 Million, with Proceeds Targeted to Reduce Debt

Oklahoma City, August 8, 2017 – Continental Resources, Inc. (NYSE: CLR) (the Company) today announced second quarter operating and financial results. Continental reported a net loss of $63.6 million, or $0.17 per diluted share, for the quarter ended June 30, 2017.

The Company's net loss includes certain items typically excluded by the investment community in published estimates, the result of which is referred to as "adjusted net loss." In second quarter 2017, these typically excluded items in aggregate represented $61.8 million, or $0.17 per diluted share, of Continental's reported net loss. Adjusted net loss for the second quarter was $1.8 million, or $0.00 per diluted share.

Net cash provided by operating activities for second quarter 2017 was $446.4 million. EBITDAX for second quarter 2017 was $479.5 million. Definitions and reconciliations of adjusted net income and net loss, adjusted net income and net loss per share, EBITDAX and cash G&A expense to the most directly comparable U.S. generally accepted accounting principles (GAAP) financial measures are provided in the supporting tables and 2017 guidance summary at the conclusion of this press release.

"Continental remained disciplined and strategic with its capital spending during the quarter," said Harold Hamm, Chairman and Chief Executive Officer. "The results have been exceptional, raising our production guidance for 2017 and lowering our guidance for operating costs. We now expect to exit 2017 with production up 24% to 31% over the fourth quarter of 2016, with a lower range of capital expenditures for the year targeting cash neutrality between $45 and $51 WTI."

Mr. Hamm noted the Company recently surpassed a significant production milestone, with individual days of output of 250,000 Boe per day. "We're bringing on a lot of pad projects. Looking ahead, given the anticipated timing of additional pad projects in the Bakken and STACK, we expect third quarter 2017 production will average 240,000 to 250,000 Boe per day, with 58% of production being crude oil," he said.

"The continuous improvements we are achieving position Continental for even better results in 2018."

Improved 2017 Guidance Reflects Superior Assets, Efficiency Gains and Disciplined Capital Program

The Company now expects annual production will be in a higher range of 230,000 to 240,000 Boe per day, compared to its previous guidance of 220,000 to 230,000 Boe per day. Continental expects to exit the year with production between 260,000 and 275,000 Boe per day, compared to the previous exit-rate guidance of 250,000 to 260,000 Boe per day. Continental is also adjusting its capital expenditures for 2017 to a range between $1.75 billion and $1.95 billion. This level of capital expenditure is expected to maintain cash neutrality at WTI prices between $45 and $51 per barrel for the year. Adjustments to capital expenditures will be accomplished primarily by reducing completion crews and rigs. The rig count for the second half of the year is projected to average 18, with 14 in Oklahoma and four in Bakken. The Company has reduced its Bakken completion crew count to four and has six crews in Oklahoma. As a result, the Company expects to exit 2017 with a drilled but uncompleted (DUC) inventory in the Bakken of approximately 160 gross operated wells, including approximately 35 already stimulated with first production expected in 2018, providing a strong catalyst for further oil focused production growth in 2018.

Continental reduced 2017 guidance for production expense per Boe, which is now expected to be in a range of $3.50 to $3.90 per Boe for the year, down from $3.50 to $4.00 per Boe.

The Company also reduced its G&A guidance for 2017, following lower G&A expense per Boe in the second quarter. Total G&A expense, which is comprised of cash and non-cash G&A expense, is expected to be $1.85 to $2.35 per Boe for 2017. Of this total, cash G&A expense is expected to be $1.35 to $1.75 per Boe for 2017, a reduction from the previous $1.50 to $2.00 per Boe. Non-cash equity compensation is expected to be $0.50 to $0.60 per Boe, a reduction from the previous $0.60 to $0.70 per Boe.

Continental also reduced 2017 guidance for DD&A to $18.00 to $20.00 per Boe for the year, down approximately 7% from the previous range.

Finally, the Company improved its outlook for oil price differentials, reflecting the impact of additional pipeline capacity in the Bakken and continued infrastructure improvements in Oklahoma. Average crude oil price differential for 2017 companywide is expected to be in a range of $5.50 to $6.50 per barrel of oil (Bo), $1.00 below the previous guidance of $6.50 to $7.50. The Company expects further improvements to its crude oil price differential in 2018. The Company also adjusted its outlook for natural gas price differentials, reflecting continued natural gas liquids price weakness. The differential is now expected to be a negative $0.10 to a negative $0.50 per Mcf.

2017 Updated Guidance Metrics	**Previous 2017 Guidance**	**Updated 2017 Guidance**
Annual production (Boe per day)	220,000 to 230,000	230,000 to 240,000
Exit rate production (Boe per day)	250,000 to 260,000	260,000 to 275,000
Capital expenditures (non-acquisition)	$1.95 billion	$1.75 to $1.95 billion
Production expense per Boe	$3.50 to $4.00	$3.50 to $3.90
Cash G&A expense per Boe[1]	$1.50 to $2.00	$1.35 to $1.75
Non-cash equity compensation per Boe	$0.60 to $0.70	$0.50 to $0.60
DD&A per Boe	$19.00 to $22.00	$18.00 to $20.00
Average price differential for NYMEX WTI crude oil (per Bo)	($6.50) to ($7.50)	($5.50) to ($6.50)
Average price differential for Henry Hub natural gas (per Mcf)	$0.10 to ($0.40)	($0.10) 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 $1.85 to $2.35 per Boe.

The Company's full 2017 guidance is stated in a table at the conclusion of this release.

"The superior quality of our assets and operations continues to translate to the bottom line," said Jack Stark, President. "As our historical performance and updated guidance show, Continental is one of the lowest cost operators in the industry, delivering some of the best margins and recycle ratios among our peers."

Production

Second quarter 2017 net production totaled 20.6 million Boe, or 226,213 Boe per day, up 12,458 Boe per day from first quarter 2017, or approximately 6%.

Total net production for second quarter 2017 included 125,381 Bo per day (55% of production) and 605 million cubic feet (MMcf) of natural gas per day (45% of production).

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

Boe per day	2Q 2017	1Q 2017	2Q 2016	YTD 2017	YTD 2016
North Region:					
North Dakota Bakken	112,397	101,012	114,554	106,736	121,861
Montana Bakken	7,464	7,980	10,474	7,720	10,454
Red River Units	9,878	10,089	11,075	9,983	11,188
Other	483	333	695	409	672
South Region:					
SCOOP	61,107	62,178	64,669	61,640	64,642
STACK	31,934	29,216	14,610	30,582	12,868
Arkoma	1,788	1,754	1,862	1,771	1,950
Other	1,162	1,193	1,384	1,177	1,428
Total	226,213	213,755	219,323	220,018	225,063

Bakken: Type Curve ROR Doubled to 82%

Continental's Bakken net production averaged 119,861 Boe per day in second quarter 2017. The Company had 100 gross (38 net) operated and non-operated Bakken wells completed during second quarter 2017. At June 30, 2017, the Company had 205 gross operated DUCs.

In the second quarter, the Company had 19 gross operated wells with first production with an average 24-hour initial production (IP) rate of 1,606 Boe per day (82% oil). Five of the second quarter wells rank in the Company's top 10 all-time producing Bakken wells, based on 30 days of production. Also during the quarter, Continental expanded the success of its optimized completions 40 miles south of existing activity in northeast McKenzie County to central Dunn County.

Based on the success of its optimized completions, the Company announced a 12% increase in its type curve EUR to 1,100 MBoe per well with a 24-hour IP of approximately 1,500 Boe. At an estimated completed well cost of $7.5 million for a 2-mile lateral well, a 1,100 MBoe EUR Bakken well will yield an 82% ROR at $50 per barrel WTI and $3.25 per Mcf of gas. This is more than double the ROR compared to the previous 980 MBoe Bakken type curve. Cumulative production at 180 days is approximately 64,000 Boe higher compared to the 980 MBoe type curve, generating over $2 million more revenue in the first six months. The new 1,100 MBoe type curve has a quicker estimated payout period of 1.25 years, compared to 2.5 years for wells with the previous type curve.

"In 2017 our Bakken team has doubled our rate of return and reduced the payout period by 50%, based on our new type curve," said Gary Gould, Senior Vice President of Production and Resource Development. "This is a step-change improvement in Bakken economics."

STACK: The Company Announces Record Well and Initial Type Curve with 80% ROR for Condensate Window

Continental's STACK net production averaged 31,934 Boe per day in second quarter 2017. The Company had 36 gross (12 net) operated and non-operated STACK wells completed during second quarter 2017. By the end of August, the Company will have nine operated rigs in the play, with seven rigs targeting the Meramec formation and two targeting the Woodford formation.

The Company reported six operated standalone wells in the STACK Meramec over-pressured oil and condensate windows. Initial 24-hour production test rates for these six wells averaged 1,915 Boe per day (45% oil) from an average 6,860-foot lateral.

In early August the Company completed a record well in STACK. The Tres C FIU 1-35-2XH flowed an impressive 1,021 Bo and 29.6 MMcf of gas (5,953 Boe) in its initial 24-hour test, with flowing casing pressure of 6,500 pounds per square inch from a 9,748-foot lateral. Adding an additional 1,978 barrels of anticipated natural gas liquids post-processing, Continental estimates the initial 24-hour IP rate for the Tres C would be a record 7,442 Boe (40% liquids) on a three-stream basis.

The Company also announced a type curve EUR of 2,400 MBoe (14% oil) for wells in the STACK over-pressured condensate window. At a targeted completed well cost of $10 million, a 9,800-foot lateral condensate well would generate an 80% ROR at $50 per barrel WTI and $3.25 per Mcf of natural gas.

The Company recently began flowing back the third of seven Meramec density tests it has in process to establish proper well spacing for future development of the Meramec reservoirs. The Blurton unit was an 8-well density test, with three new wells in the upper Meramec and four new wells and the existing parent well in the lower Meramec. Average lateral length was approximately 10,000 feet per well. The unit is still in the early stages of flowing back and has not reached peak production rates. To date the combined 24-hour initial rate recorded from the eight wells is 10,514 Boe per day, with 78% of production being oil. Including estimated post-processing natural gas liquids, the combined 24-hour IP rate would have been approximately 11,883 Boe per day. The Company continues to monitor the flowback of these wells and will incorporate the results from the Blurton with those of other density tests to guide future development in STACK.

SCOOP: Springer Shines

In second quarter 2017, SCOOP net production averaged 61,107 Boe per day (27% oil). Continental had 8 gross (2 net) operated and non-operated wells completed during second quarter 2017. Continental currently has five operated drilling rigs working in SCOOP, targeting the Springer, Sycamore and Woodford formations.

During the quarter, Continental announced one SCOOP Springer well, the Robinson 2-15-10XHS. The initial 24-hour production test rate was 1,636 Boe per day (82% oil) from a 7,700-foot lateral. The Robinson outperformed the Company's historical 940 MBoe Springer type curve by 89% in the first 60 days on production.

Last quarter, the Company announced the completion of the Cash 1-26H, an optimized Springer producing well. At 90 days the Cash outperformed the Company's 940 MBoe type curve by 82%. At a cost of $7.6 million and an estimated EUR of 1,160 MBoe, the Cash well has an estimated rate of return of over 100% and pays out in 12 months, assuming $50 per barrel WTI and $3.25 per Mcf of gas. Longer laterals, combined with shorter drill times and optimized completions, are improving Springer well economics.

A notable second quarter well in the SCOOP Woodford oil window was the Romanoff 1-25-24-13XH in eastern Grady County, which had a 24-hour IP rate of 1,188 Bo and 2.3 MMcf (1,563 Boe) from a 14,900-foot lateral. This was the Company's first 3-mile lateral well in SCOOP. At 30 days, the well was outperforming offset wells by over 25%, when normalized to a 7,500-foot lateral, and had an average 30-day production rate of 1,424 Boe per day (75% oil).

Two other recent completions in the SCOOP Woodford condensate window were the Renea 1-23-14XH and Cottonwood East 1-25-24XH wells. The Renea's 24-hour IP was 2,322 Boe per day (18% oil) from a 10,160-foot lateral. The Cottonwood East's 24-hour IP was 1,918 (34% oil) from a 7,800-foot lateral. The Renea and Cottonwood outperformed legacy offset wells by 80% to 90% during their first 30 days. They are located in an area of Stephens County where the Company has not been active for the past two years.

Company Agrees to Sell Non-Strategic Leasehold and Property for $147.5 Million

Continental announced today it has signed two definitive purchase and sale agreements with undisclosed buyers to sell 6,590 net acres of non-core leasehold in the oil window of STACK in northern Blaine County, Oklahoma for $72.5 million, and 26,000 net acres of leasehold in the Arkoma Basin located in Atoka, Coal, Hughes and Pittsburg counties, Oklahoma for $68.0 million. The leaseholds are non-strategic and include minimal proved reserves. The agreements provide for customary closing conditions and adjustments. The Company is also selling oil-loading facilities in Oklahoma for $7.0 million. The Company intends to use the proceeds from the sales to reduce outstanding debt and noted that it has other opportunities for non-core asset sales.

Financial Update

“Continental’s results through the first half of the year reflect strong outperformance and continued operating cost and capital expenditure discipline,” said John Hart, Chief Financial Officer. “We are raising our production estimates while lowering guidance for operating costs. The updated guidance metrics are expected to be achieved while targeting cash neutrality between $45 and $51 WTI with capital expenditures ranging from $1.75 billion to $1.95 billion.

“Oil production was 55% of total production for second quarter, slightly lower than consensus primarily due to working interest adjustments. For third quarter we are projecting production to be 58% oil as additional Bakken and Springer wells are completed.”

In second quarter 2017, Continental’s average realized sales price excluding the effects of derivative positions was $41.91 per barrel of oil and $2.63 per Mcf of gas, or $30.31 per Boe. Based on realizations without the effect of derivatives, the Company’s second quarter 2017 oil differential was $6.31 per barrel below the NYMEX daily average for the period, $0.78 better than the first quarter differential. The realized wellhead natural gas price for the quarter was on average $0.56 per Mcf below the average NYMEX Henry Hub benchmark price.

Production expense per Boe was $3.99 for second quarter 2017. Other select operating costs and expenses for second quarter 2017 included production taxes of 6.7% of oil and natural gas sales, DD&A of $19.14 per Boe, and total G&A of $1.89 per Boe.

Non-acquisition capital expenditures for second quarter 2017 totaled approximately $551.9 million. Non-acquisition capital expenditures for the quarter included $471.0 million in exploration and development drilling, $51.6 million in leasehold and seismic, and $29.3 million in workovers, recompletions and other.

As of June 30, 2017, Continental’s balance sheet included approximately $17.2 million in cash and cash equivalents and $6.56 billion in long-term debt, essentially in-line with first quarter 2017.

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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Average daily production:				
Crude oil (Bbl per day)	125,381	133,044	122,308	139,756
Natural gas (Mcf per day)	604,991	517,677	586,263	511,837
Crude oil equivalents (Boe per day)	226,213	219,323	220,018	225,063
Average sales prices, excluding effect from derivatives:				
Crude oil ($/Bbl)	$41.91	$38.38	$43.26	$31.76
Natural gas ($/Mcf)	$2.63	$1.31	$2.81	$1.33
Crude oil equivalents ($/Boe)	$30.31	$26.36	$31.56	$22.73
Production expenses ($/Boe)	$3.99	$3.72	$3.89	$3.74
Production taxes (% of oil and gas revenues)	6.7%	7.4%	6.6%	7.5%
DD&A ($/Boe)	$19.14	$22.15	$19.48	$22.16
Total general and administrative expenses ($/Boe) (1)	$1.89	$1.82	$2.16	$1.68
Net loss (in thousands)	($63,557)	($119,402)	($63,088)	($317,727)
Diluted net loss per share	($0.17)	($0.32)	($0.17)	($0.86)
Adjusted net income (loss) (non-GAAP) (in thousands) (2)	($1,801)	($65,910)	$4,979	($216,378)
Adjusted diluted net income (loss) per share (non-GAAP) (2)	$0.00	($0.18)	$0.01	($0.58)
Net cash provided by operating activities	$446,371	$218,819	$916,572	$497,721
EBITDAX (non-GAAP) (in thousands) (2)	$479,490	$528,109	$961,963	$842,718

(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 $1.45, $1.22, $1.65, and $1.16 for 2Q 2017, 2Q 2016, YTD 2017 and YTD 2016, respectively. Non-cash equity compensation expense per Boe was $0.44, $0.60, $0.51, and $0.52 for 2Q 2017, 2Q 2016, YTD 2017 and YTD 2016, respectively.

(2) 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*.

Second Quarter Earnings Conference Call

Continental plans to host a conference call to discuss second quarter results on Wednesday, August 9, 2017, 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, Wednesday, August 9, 2017
Dial in:	844-309-6572
Intl. dial in:	484-747-6921
Pass code:	30586076

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:	30586076

Continental plans to publish a second quarter 2017 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on August 9, 2017.

Upcoming Conferences

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

August 23, 2017	Heikkinen Energy Conference, Houston
September 5-6, 2017	Barclays CEO Energy-Power Conference, New York
September 27-28, 2017	Deutsche Bank Annual Energy 1x1 Conference, Boston

About Continental Resources

Continental Resources (NYSE: CLR) is a top 15 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 one of the largest producers 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, SCOOP Springer and SCOOP Sycamore 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 2017, the Company will celebrate 50 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 December 31, 2016, 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.

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Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Loss

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	In thousands, except per share data			
Revenues:				
Crude oil and natural gas sales	$ 626,548	$ 525,711	$ 1,260,398	$ 929,302
Gain (loss) on crude oil and natural gas derivatives, net	28,022	(82,257)	74,880	(40,145)
Crude oil and natural gas service operations	6,916	7,757	11,636	15,227
Total revenues	661,486	451,211	1,346,914	904,384
Operating costs and expenses:				
Production expenses	82,474	74,083	155,328	152,724
Production taxes	41,965	39,141	83,198	69,634
Exploration expenses	3,204	1,674	8,202	4,739
Crude oil and natural gas service operations	4,478	3,576	7,315	6,618
Depreciation, depletion, amortization and accretion	395,770	441,761	777,926	905,752
Property impairments	123,316	66,112	174,689	145,039
General and administrative expenses	39,186	36,246	86,407	68,654
Net (gain) loss on sale of assets and other	134	(100,835)	5,669	(99,127)
Total operating costs and expenses	690,527	561,758	1,298,734	1,254,033
Income (loss) from operations	(29,041)	(110,547)	48,180	(349,649)
Other income (expense):				
Interest expense	(72,744)	(81,922)	(143,916)	(162,875)
Other	373	435	815	819
	(72,371)	(81,487)	(143,101)	(162,056)
Loss before income taxes	(101,412)	(192,034)	(94,921)	(511,705)
Benefit for income taxes	37,855	72,632	31,833	193,978
Net loss	$ (63,557)	$ (119,402)	$ (63,088)	$ (317,727)
Basic net loss per share	$ (0.17)	$ (0.32)	$ (0.17)	$ (0.86)
Diluted net loss per share	$ (0.17)	$ (0.32)	$ (0.17)	$ (0.86)

Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Balance Sheets

	June 30, 2017		December 31, 2016	
Assets	*In thousands*			
Current assets	$	934,042	$	913,233
Net property and equipment [1]		12,921,875		12,881,227
Other noncurrent assets		15,340		17,316
Total assets	$	13,871,257	$	13,811,776
Liabilities and shareholders' equity				
Current liabilities	$	1,094,978	$	932,393
Long-term debt, net of current portion		6,553,740		6,577,697
Other noncurrent liabilities		1,968,204		1,999,690
Total shareholders' equity		4,254,335		4,301,996
Total liabilities and shareholders' equity	$	13,871,257	$	13,811,776

(1) Balance is net of accumulated depreciation, depletion and amortization of $8.49 billion and $7.65 billion as of June 30, 2017 and December 31, 2016, respectively.

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

	Three months ended June 30,				Six months ended June 30,			
In thousands	2017		2016		2017		2016	
Net loss	$	(63,557)	$	(119,402)	$	(63,088)	$	(317,727)
Adjustments to reconcile net loss to net cash provided by operating activities:								
Non-cash expenses		465,966		470,257		877,921		903,030
Changes in assets and liabilities		43,962		(132,036)		101,739		(87,582)
Net cash provided by operating activities		446,371		218,819		916,572		497,721
Net cash used in investing activities		(490,049)		(158,983)		(879,320)		(517,794)
Net cash (used in) provided by financing activities		43,666		(56,181)		(36,719)		25,161
Effect of exchange rate changes on cash		14		(22)		14		9
Net change in cash and cash equivalents		2		3,633		547		5,097
Cash and cash equivalents at beginning of period		17,188		12,927		16,643		11,463
Cash and cash equivalents at end of period	$	17,190	$	16,560	$	17,190	$	16,560

Non-GAAP Financial Measures

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 (loss) or net cash provided by operating activities 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 net cash provided by operating activities 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 net cash provided by operating activities 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 loss to EBITDAX for the periods presented.

	Three months ended June 30,		Six months ended June 30,	
In thousands	2017	2016	2017	2016
Net loss	$ (63,557)	$ (119,402)	$ (63,088)	$ (317,727)
Interest expense	72,744	81,922	143,916	162,875
Benefit for income taxes	(37,855)	(72,632)	(31,833)	(193,978)
Depreciation, depletion, amortization and accretion	395,770	441,761	777,926	905,752
Property impairments	123,316	66,112	174,689	145,039
Exploration expenses	3,204	1,674	8,202	4,739
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	(27,109)	78,057	(72,070)	37,005
Total cash received on derivatives, net	3,844	38,778	3,650	77,967
Non-cash (gain) loss on derivatives, net	(23,265)	116,835	(68,420)	114,972
Non-cash equity compensation	9,133	11,839	20,571	21,046
EBITDAX (non-GAAP)	$ 479,490	$ 528,109	$ 961,963	$ 842,718

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

In thousands	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Net cash provided by operating activities	$ 446,371	$ 218,819	$ 916,572	$ 497,721
Current income tax provision	-	6	1	12
Interest expense	72,744	81,922	143,916	162,875
Exploration expenses, excluding dry hole costs	3,204	1,468	8,045	4,533
Gain (loss) on sale of assets, net	780	96,907	(2,859)	97,016
Other, net	353	(3,049)	(1,973)	(7,021)
Changes in assets and liabilities	(43,962)	132,036	(101,739)	87,582
EBITDAX (non-GAAP)	$ 479,490	$ 528,109	$ 961,963	$ 842,718

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, gains and losses on asset sales, and losses on extinguishment of debt. 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 table reconciles 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 June 30,			
	2017		2016	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net loss (GAAP)	$ (63,557)	$ (0.17)	$ (119,402)	$ (0.32)
Adjustments:				
Non-cash (gain) loss on derivatives	(23,265)		116,835	
Property impairments	123,316		66,112	
Gain on sale of assets	(780)		(96,907)	
Total tax effect of adjustments	(37,515)		(32,548)	
Total adjustments, net of tax	61,756	0.17	53,492	0.14
Adjusted net loss (non-GAAP)	$ (1,801)	$0.00	$ (65,910)	$ (0.18)
Weighted average diluted shares outstanding	371,111		370,435	
Adjusted diluted net loss per share (non-GAAP)	$0.00		$ (0.18)	

	Six months ended June 30,			
	2017		2016	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net loss (GAAP)(1)	$ (63,088)	$ (0.17)	$ (317,727)	$ (0.86)
Adjustments:				
Non-cash (gain) loss on derivatives	(68,420)		114,972	
Property impairments	174,689		145,039	
(Gain) loss on sale of assets	2,859		(97,016)	
Total tax effect of adjustments	(41,061)		(61,646)	
Total adjustments, net of tax	68,067	0.18	101,349	0.28
Adjusted net income (loss) (non-GAAP)	$ 4,979	$ 0.01	$ (216,378)	$ (0.58)
Weighted average diluted shares outstanding	373,518		370,248	
Adjusted diluted net income (loss) per share (non-GAAP)	$ 0.01		$ (0.58)	

(1) In 1Q 2017 we adopted ASU 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* , which requires, among other things, that companies recognize excess tax benefits and deficiencies from stock-based compensation as income tax benefit or expense in the income statement rather than through additional paid-in capital. This change resulted in a $3.8 million ($0.01 per diluted share) increase in net loss for YTD 2017 with no comparable impact in the prior period.

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.

Continental Resources, Inc.
2017 Guidance[1]
As of August 8, 2017

	2017
Full year average production	**230,000 to 240,000 Boe per day**
Exit rate average production	**260,000 to 275,000 Boe per day**
Capital expenditures (non-acquisition)	**$1.75 to $1.95 billion**
Operating Expenses:	
Production expense per Boe	**$3.50 to $3.90**
Production tax (% of oil & gas revenue)	6.75% to 7.25%
Cash G&A expense per Boe[2]	**$1.35 to $1.75**
Non-cash equity compensation per Boe	**$0.50 to $0.60**
DD&A per Boe	**$18.00 to $20.00**
Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	**($5.50) to ($6.50)**
Henry Hub natural gas (per Mcf)	**($0.10) to ($0.50)**
Income tax rate	38%
Deferred taxes	90% to 95%

(1) Changed items are shown in bold
(2) 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 $1.85 to $2.35 per Boe.