NEWS RELEASE

# CONTINENTAL RESOURCES REPORTS THIRD QUARTER 2017 RESULTS

**Net Income of $10.6 Million, or $0.03 per Diluted Share, In Line with Consensus**

**Capital Spending In Line with $1.95 Billion Budget**

**Oil Production Up 12% Over 2Q 2017; 58% of Third Quarter Production Was Oil**

**Guidance Improved:**

- **2017 exit rate raised to 280,000 to 290,000 barrels of oil equivalent (Boe) per day, up 33% to 38% over 4Q 2016**
- **Annual production raised to 238,000 to 242,000 Boe per day, up 10% to 12% over 2016**
- **Annual oil differential improved to ($5.25) to ($5.75) per barrel of oil (Bo), a 22% to 28% improvement over 2016**
- **4Q 2017 oil differential expected to be ($4.25) to ($4.75) per Bo**

**Average 24-Hour Initial Production (IP) Highlights:**

- **Bakken: 57 gross operated wells average 1,752 Boe (80% oil) per well**
- **STACK Meramec oil window: 22,032 Boe (75% oil) from 10-well Compton density unit**
- **STACK Meramec condensate window: 6,715 Boe (28% oil) from Lorene 1-8-5XH; Oklahoma horizontal well record**
- **SCOOP Woodford condensate window: 41,701 Boe (11% oil) from 10-well pattern Sympson density unit; Oklahoma unit record**

Oklahoma City, November 7, 2017 – Continental Resources, Inc. (NYSE: CLR) (the Company) today announced third quarter operating and financial results. Continental reported net income of $10.62 million, or $0.03 per diluted share, for the quarter ended September 30, 2017.

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 third quarter 2017, these typically excluded items in aggregate represented $21.54 million, or $0.06 per diluted share, which reduced Continental's reported net income. Adjusted net income for the third quarter was $32.16 million, or $0.09 per diluted share.

Net cash provided by operating activities for third quarter 2017 was $431.4 million. EBITDAX for third quarter 2017 was $563.8 million. Definitions and reconciliations of adjusted net income (loss), adjusted net income (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’s performance year-to-date demonstrates industry leadership in capital disciplined production growth,” said Harold Hamm, Chairman and Chief Executive Officer. “Continental’s operations continue to become more capital efficient each quarter, allowing us to sustain our low-cost advantage. Additionally, due to continued strong well performance in all of our plays, we are raising our exit rate production guidance to 280,000 to 290,000 Boe per day, a 33% to 38% increase over fourth quarter 2016. This positions us for strong, cash-flow-positive growth in 2018.”

**Crude Oil Represents 58% of Third Quarter Total Production**

Third quarter 2017 net production totaled 22.3 million Boe, or 242,788 Boe per day, up 7% over second quarter 2017. Crude oil production was 140,611 Bo per day, or 58% of production, for third quarter 2017, a 12% increase over second quarter. Natural gas production averaged 613.1 million cubic feet (MMcf) per day, or 42% of production.

Third quarter production was negatively impacted in September by unusually rainy weather in the Bakken as well as midstream curtailments in Oklahoma associated with Hurricane Harvey. The net impact on third quarter production was a reduction of approximately 3,500 Boe per day. Apart from these two events, estimated production for the third quarter would have been in excess of 246,000 Boe per day. October production is estimated to be in excess of 275,000 Boe per day, with 59% being oil.

Fourth quarter average daily oil production is expected to be 14% to 18% higher than third quarter. Total fourth quarter 2017 production is expected to be in a range of 275,000 to 285,000 Boe per day, and the 2017 exit rate production is now expected to be in a range of 280,000 to 290,000 Boe per day. Full-year 2017 production is expected to be in a range of 238,000 to 242,000 Boe per day.

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

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

| *Boe per day* | 3Q 2017 | 2Q 2017 | 3Q 2016 | YTD 2017 | YTD 2016 |
|---|---|---|---|---|---|
| North Region: | | | | | |
| North Dakota Bakken | 129,582 | 112,397 | 99,251 | 114,435 | 114,269 |
| Montana Bakken | 7,269 | 7,464 | 8,678 | 7,569 | 9,858 |
| Red River Units | 9,536 | 9,878 | 10,475 | 9,832 | 10,949 |
| Other | 449 | 483 | 1,189 | 422 | 845 |
| South Region: | | | | | |
| SCOOP | 57,283 | 61,107 | 67,462 | 60,171 | 65,589 |
| STACK | 35,619 | 31,934 | 17,680 | 32,280 | 14,484 |
| Arkoma(1) | 1,722 | 1,788 | 1,833 | 1,755 | 1,911 |
| Other | 1,328 | 1,162 | 1,272 | 1,228 | 1,375 |
| Total | 242,788 | 226,213 | 207,840 | 227,692 | 219,280 |

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

**Bakken: Increasing Value Through Technology**

Continental’s Bakken net production averaged 136,851 Boe per day in third quarter 2017, a 14% increase over second quarter 2017 production. The Company completed 122 gross (58 net) operated and non-operated Bakken wells during the quarter. The Company currently has four operated drilling rigs and four stimulation crews active in the Bakken. At September 30, 2017, the Company had 172 gross operated drilled but uncompleted or completed but not producing wells (DUCs). The Company expects to end 2017 with approximately 150 DUCs in inventory.

In the third quarter, the Company had 57 gross operated wells with first production, with an average 24-hour IP rate of 1,752 Boe per day (80% oil). Fifteen of the wells posted 24-hour IP rates of more than 2,000 Boe per day. All of the wells were completed using the Company’s optimized completion technology that includes various combinations of larger proppant loads, tighter stage spacing and diverters, along with accelerated flow backs and high-capacity lift. Through third quarter 2017, the Company has brought on over 100 Bakken optimized wells, and their average production is in line with and slightly outperforming the Company’s updated Bakken type curve announced last quarter. The new 1,100 MBoe Bakken type curve includes a 12% uplift in estimated ultimate recovery (EUR) and doubles the expected rate of return to 82% at $50 WTI, compared with the Company’s previous type curve. The increased type curve yields approximately $2 million of gross incremental cash flow per well during the first year, cutting payouts in half to approximately 15 months per well.

“Our optimized completions are unlocking more value from our Bakken assets than ever before,” said Jack Stark, President. “This is a key catalyst that will drive our ability to deliver cash-flow-positive, oil-weighted growth for years to come.”

The Company also continued to improve key Bakken operating metrics during the third quarter. Average spud-to-total-depth drilling time for the third quarter was 10.5 days, a quarter-over-quarter improvement of 8% and an improvement of 27% compared with 2016’s average drilling time. As a result, average drilling cost per well was down nearly 6% from the second quarter and approximately 25% below the 2016 average.

**STACK: Over-Pressured Oil Window Density Test Delivers Strong Results**

Continental’s STACK net production averaged 35,619 Boe per day in third quarter 2017, a 12% increase over second quarter 2017. The Company completed 32 gross (15.2 net) operated and non-operated STACK wells during the quarter. The Company currently has nine operated drilling rigs in the play, with six of the rigs targeting the Woodford and Meramec formations as part of the joint development agreement with SK E&S.

The Company recently began flowing back a new Meramec density test in the over-pressured oil window of STACK at the Compton unit. The Compton was a 10-well density unit, with five new wells in the upper Meramec and four new wells and one parent well in the lower Meramec. Average lateral length was approximately 10,200 feet per well. The 10 wells flowed at a combined peak 24-hour rate of 22,032 Boe (75% oil) or 2,203 Boe per day per well. Early performance shows the wells on average are performing in line with the Company’s oil window type curve of 1.7 MMBoe. Average completed well cost for the nine new Compton wells was approximately $9.2 million, down approximately 28% from the cost of the parent well.

The Company also reported results from seven operated standalone wells in the STACK Meramec over-pressured oil and condensate windows. The average 24-hour IPs for the seven wells was 3,736 Boe per day (40% oil) from an average 8,387-foot lateral.

Three notable wells were the R Moore 1-24H, the Edward Lee 1-13-12XH and the Lorene 1-8-5XH. The R Moore had an impressive 24-hour IP of 3,565 Boe per day (71% oil) from a 4,890-foot lateral. The Edward Lee had a 24-hour IP of 1,857 Boe per day (3% oil) from a 9,725-foot lateral. The Edward Lee is the Company’s first Meramec well in Dewey County, and it’s the farthest west Meramec completion to date for Continental. These two wells had flowing casing pressures of 3,800 and 4,500 pounds per square inch (psi), respectively.

The Lorene 1-8-5XH well was recently completed, setting a new 24-hour initial rate record for horizontal wells in Oklahoma. The Lorene produced at a maximum 24-hour flow rate of 1,863 barrels of oil and 29.1 MMcf per day, or 6,715 Boe, at 5,575 psi flowing casing pressure from a 10,200-foot lateral. This exceeds the record rate previously announced by the Company from the Tres C FIU 1-35-2XH. The Tres C produced at an average rate of 5,345 Boe per day in its first 30 days and is currently producing approximately 3,600 Boe per day with a flowing casing pressure of 3,375 psi. The Lorene is located two miles east of the Tres C well in Blaine County.

**SCOOP Woodford: Oklahoma Record Unit Production from Sympson Density Test**

In third quarter 2017, SCOOP net production averaged 57,283 Boe per day (26% oil). Continental had 30 gross (7.1 net) operated and non-operated wells completed during third quarter 2017. Continental currently has five operated drilling rigs working in SCOOP, targeting the Springer, Sycamore and Woodford formations.

Continental recently completed its third 10-well pattern density project in the SCOOP Woodford condensate window, setting an Oklahoma record for an initial rate reported from a drilling spacing unit. The Sympson unit flowed at a combined peak 24-hour rate of 4,652 Bo and 222.3 MMcf per day (41,701 Boe per day).

The Sympson unit is a two-mile long, dual-zone, 10-well pattern unit that includes a total of 14 wells. Two one-mile parent wells and 12 children wells of various lengths were required to fill in the 10-well 1,280-acre unit pattern. This resulted in the equivalent of 5 wells in the Upper Woodford and 5 wells in the Lower Woodford. The 12 new wells produced at an average 24-hour peak production rate of 3,145 Boe per day (11% oil), and on average the wells are performing in line with the 2.3 MMBoe type curve. Lateral lengths ranged from 3,050 to 10,270 feet.

**SCOOP Springer: Recent Wells Continue to Outperform Legacy Type Curve by 70%**

Recently completed SCOOP Springer wells continue to outperform the Company's legacy 940 MBoe type curve, benefiting from optimized completions and longer laterals. Average production from the previously announced Cash, Trammell, Strassle, and Robinson wells is approximately 70% above the Springer type curve at 150 days.

During the third quarter, activity in SCOOP Springer was focused on an ongoing 6-well density test at the Celesta unit. This is the Company's first two-mile lateral density test in the Springer, and results are expected by early 2018.

**Financial Update**

"Continental's focus on capital efficiency and cash flow continues to yield results," said John Hart, Chief Financial Officer. "Our cash flows are strong and improving with rising production and improved commodity prices, each positively benefiting our leverage ratios. We see this trend continuing. We also continue to make progress towards our near-term debt reduction target of $6.0 billion and our longer-term goal of $5.0 billion. We recently closed on three separate transactions totaling $136 million, and we are actively marketing several larger packages."

In third quarter 2017, Continental's average realized sales price excluding the effects of derivative positions was $43.27 per barrel of oil and $2.74 per Mcf of gas, or $31.86 per Boe. Based on realizations without the effect of derivatives, the Company's third quarter 2017 oil differential was $4.98 per barrel below the NYMEX daily average for the period, $1.33 better than the second quarter differential. The realized wellhead natural gas price differential was $0.26 per Mcf below the average NYMEX Henry Hub benchmark price, $0.30 better than the second quarter average due primarily to stronger liquids pricing. The month of September had a premium of $0.02 per Mcf above the average NYMEX Henry Hub benchmark price.

Production expense per Boe was $3.82 for third quarter 2017. Other select operating costs and expenses for third quarter 2017 included production taxes of 7.3% of oil and natural gas sales, DD&A of $19.00 per Boe, and total G&A of $1.99 per Boe.

Non-acquisition capital expenditures for third quarter 2017 totaled approximately $520.6 million. They included $444.7 million in exploration and development drilling, $47.7 million in leasehold and seismic, and $28.2 million in workovers, recompletions and other.

As of September 30, 2017, Continental's balance sheet included approximately $10.8 million in cash and cash equivalents and $6.6 billion in long-term debt. During the third quarter the Company closed on the previously announced sale of 26,000 net acres in the Arkoma Basin, oil-loading facilities and other divestitures for $76.1 million. Another previously announced divestiture closed in October for approximately $59.9 million.

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 September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Average daily production: | | | | |
| Crude oil (Bbl per day) | 140,611 | 116,277 | 128,476 | 131,873 |
| Natural gas (Mcf per day) | 613,060 | 549,374 | 595,294 | 524,441 |
| Crude oil equivalents (Boe per day) | 242,788 | 207,840 | 227,692 | 219,280 |
| Average sales prices, excluding effect from derivatives: | | | | |
| Crude oil ($/Bbl) | $43.27 | $37.66 | $43.26 | $33.51 |
| Natural gas ($/Mcf) | $2.74 | $2.02 | $2.78 | $1.57 |
| Crude oil equivalents ($/Boe) | $31.86 | $26.42 | $31.67 | $23.91 |
| Production expenses ($/Boe) | $3.82 | $3.50 | $3.86 | $3.66 |
| Production taxes (% of oil and gas revenues) | 7.3% | 6.8% | 6.8% | 7.3% |
| DD&A ($/Boe) | $19.00 | $21.66 | $19.31 | $22.00 |
| Total general and administrative expenses ($/Boe) (1) | $1.99 | $2.32 | $2.10 | $1.88 |
| Net income (loss) (in thousands) | $10,621 | ($109,621) | ($52,467) | ($427,348) |
| Diluted net income (loss) per share | $0.03 | ($0.30) | ($0.14) | ($1.15) |
| Adjusted net income (loss) (non-GAAP) (in thousands) (2) | $32,162 | ($82,853) | $37,142 | ($299,232) |
| Adjusted diluted net income (loss) per share (non-GAAP) (2) | $0.09 | ($0.22) | $0.10 | ($0.81) |
| Net cash provided by operating activities | $431,409 | $366,167 | $1,347,981 | $863,888 |
| EBITDAX (non-GAAP) (in thousands) (2) | $563,767 | $386,789 | $1,525,730 | $1,229,507 |

(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, $1.63, $1.58, and $1.31 for 3Q 2017, 3Q 2016, YTD 2017 and YTD 2016, respectively. Non-cash equity compensation expense per Boe was $0.54, $0.69, $0.52, and $0.57 for 3Q 2017, 3Q 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* .

## Third Quarter Earnings Conference Call

Continental plans to host a conference call to discuss third quarter results on Wednesday, November 8, 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, November 8, 2017
Dial in: 844-309-6572
Intl. dial in: 484-747-6921
Pass code: 89145961

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: 89145961

Continental plans to publish a third quarter 2017 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on November 8, 2017.

## Upcoming Conferences

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

| | |
|---|---|
| November 15-16, 2017 | Bank of America Merrill Lynch Global Energy Conference, Miami |
| November 28, 2017 | Capital One Bakken Deep Dive, New York |
| November 28, 2017 | Jefferies 2017 Energy Conference, Houston |

## 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 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, 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 Income (Loss)

| | Three months ended September 30, 2017 | Three months ended September 30, 2016 | Nine months ended September 30, 2017 | Nine months ended September 30, 2016 |
|---|---|---|---|---|
| | *In thousands, except per share data* | | | |
| Revenues: | | | | |
| Crude oil and natural gas sales | $ 704,818 | $ 505,892 | $ 1,965,216 | $ 1,435,194 |
| Gain (loss) on crude oil and natural gas derivatives, net | 8,602 | 15,668 | 83,482 | (24,477) |
| Crude oil and natural gas service operations | 13,323 | 4,639 | 24,959 | 19,867 |
| Total revenues | 726,743 | 526,199 | 2,073,657 | 1,430,584 |
| Operating costs and expenses: | | | | |
| Production expenses | 84,514 | 67,022 | 239,842 | 219,745 |
| Production taxes | 51,264 | 34,583 | 134,462 | 104,216 |
| Exploration expenses | 1,389 | 3,987 | 9,591 | 8,726 |
| Crude oil and natural gas service operations | 3,349 | 2,605 | 10,664 | 9,224 |
| Depreciation, depletion, amortization and accretion | 420,243 | 414,671 | 1,198,169 | 1,320,423 |
| Property impairments | 35,130 | 57,689 | 209,819 | 202,728 |
| General and administrative expenses | 44,006 | 44,389 | 130,413 | 113,043 |
| Net (gain) loss on sale of assets and other | (4,905) | (5,564) | 764 | (104,690) |
| Total operating costs and expenses | 634,990 | 619,382 | 1,933,724 | 1,873,415 |
| Income (loss) from operations | 91,753 | (93,183) | 139,933 | (442,831) |
| Other income (expense): | | | | |
| Interest expense | (74,756) | (82,074) | (218,672) | (244,949) |
| Other | 394 | 360 | 1,209 | 1,178 |
| | (74,362) | (81,714) | (217,463) | (243,771) |
| Income (loss) before income taxes | 17,391 | (174,897) | (77,530) | (686,602) |
| (Provision) benefit for income taxes | (6,770) | 65,276 | 25,063 | 259,254 |
| Net income (loss) | $ 10,621 | $ (109,621) | $ (52,467) | $ (427,348) |
| Basic net income (loss) per share | $ 0.03 | $ (0.30) | $ (0.14) | $ (1.15) |
| Diluted net income (loss) per share | $ 0.03 | $ (0.30) | $ (0.14) | $ (1.15) |

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

| | September 30, 2017 | December 31, 2016 |
|---|---|---|
| **Assets** | *In thousands* | |
| Current assets | $ 1,060,975 | $ 913,233 |
| Net property and equipment [(1)] | 12,919,202 | 12,881,227 |
| Other noncurrent assets | 14,910 | 17,316 |
| Total assets | $ 13,995,087 | $ 13,811,776 |
| | | |
| **Liabilities and shareholders' equity** | | |
| Current liabilities | $ 1,129,459 | $ 932,393 |
| Long-term debt, net of current portion | 6,612,281 | 6,577,697 |
| Other noncurrent liabilities | 1,976,568 | 1,999,690 |
| Total shareholders' equity | 4,276,779 | 4,301,996 |
| Total liabilities and shareholders' equity | $ 13,995,087 | $ 13,811,776 |

(1) Balance is net of accumulated depreciation, depletion and amortization of $8.64 billion and $7.65 billion as of September 30, 2017 and December 31, 2016, respectively.

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

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *In thousands* | 2017 | 2016 | 2017 | 2016 |
| Net income (loss) | $ 10,621 | $ (109,621) | $ (52,467) | $ (427,348) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | | |
| Non-cash expenses | 480,718 | 415,690 | 1,358,639 | 1,318,720 |
| Changes in assets and liabilities | (59,930) | 60,098 | 41,809 | (27,484) |
| Net cash provided by operating activities | 431,409 | 366,167 | 1,347,981 | 863,888 |
| Net cash used in investing activities | (494,934) | (32,427) | (1,374,254) | (550,221) |
| Net cash provided by (used in) financing activities | 57,080 | (330,802) | 20,361 | (305,641) |
| Effect of exchange rate changes on cash | 20 | (2) | 34 | 7 |
| Net change in cash and cash equivalents | (6,425) | 2,936 | (5,878) | 8,033 |
| Cash and cash equivalents at beginning of period | 17,190 | 16,560 | 16,643 | 11,463 |
| Cash and cash equivalents at end of period | $ 10,765 | $ 19,496 | $ 10,765 | $ 19,496 |

## 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 income (loss) to EBITDAX for the periods presented.

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *In thousands* | 2017 | 2016 | 2017 | 2016 |
| Net income (loss) | $ 10,621 | $ (109,621) | $ (52,467) | $ (427,348) |
| Interest expense | 74,756 | 82,074 | 218,672 | 244,949 |
| Provision (benefit) for income taxes | 6,770 | (65,276) | (25,063) | (259,254) |
| Depreciation, depletion, amortization and accretion | 420,243 | 414,671 | 1,198,169 | 1,320,423 |
| Property impairments | 35,130 | 57,689 | 209,819 | 202,728 |
| Exploration expenses | 1,389 | 3,987 | 9,591 | 8,726 |
| Impact from derivative instruments: | | | | |
| Total (gain) loss on derivatives, net | (9,945) | (15,237) | (82,015) | 21,768 |
| Total cash received on derivatives, net | 12,884 | 5,274 | 16,534 | 83,241 |
| Non-cash (gain) loss on derivatives, net | 2,939 | (9,963) | (65,481) | 105,009 |
| Non-cash equity compensation | 11,919 | 13,228 | 32,490 | 34,274 |
| EBITDAX (non-GAAP) | $ 563,767 | $ 386,789 | $ 1,525,730 | $ 1,229,507 |

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 September 30, 2017 | Three months ended September 30, 2016 | Nine months ended September 30, 2017 | Nine months ended September 30, 2016 |
|---|---|---|---|---|
| Net cash provided by operating activities | $ 431,409 | $ 366,167 | $ 1,347,981 | $ 863,888 |
| Current income tax provision (benefit) | (1) | (10) | - | 2 |
| Interest expense | 74,756 | 82,074 | 218,672 | 244,949 |
| Exploration expenses, excluding dry hole costs | 1,389 | 3,960 | 9,434 | 8,493 |
| Gain on sale of assets, net | 3,562 | 6,158 | 703 | 103,174 |
| Tax deficiency from stock-based compensation | - | (9,460) | - | (9,460) |
| Other, net | (7,278) | (2,002) | (9,251) | (9,023) |
| Changes in assets and liabilities | 59,930 | (60,098) | (41,809) | 27,484 |
| EBITDAX (non-GAAP) | $ 563,767 | $ 386,789 | $ 1,525,730 | $ 1,229,507 |

***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.

| In thousands, except per share data | Three months ended September 30, 2017 $ | 2017 Diluted EPS | 2016 $ | 2016 Diluted EPS |
|---|---|---|---|---|
| Net income (loss) (GAAP) | $ 10,621 | $ 0.03 | $ (109,621) | $ (0.30) |
| Adjustments: | | | | |
| Non-cash (gain) loss on derivatives | 2,939 | | (9,963) | |
| Property impairments | 35,130 | | 57,689 | |
| Gain on sale of assets | (3,562) | | (6,158) | |
| Total tax effect of adjustments | (12,966) | | (14,800) | |
| Total adjustments, net of tax | 21,541 | 0.06 | 26,768 | 0.08 |
| Adjusted net income (loss) (non-GAAP) | $ 32,162 | $ 0.09 | $ (82,853) | $ (0.22) |
| Weighted average diluted shares outstanding | 373,015 | | 370,483 | |
| Adjusted diluted net income (loss) per share (non-GAAP) | $0.09 | | $ (0.22) | |

| In thousands, except per share data | Nine months ended September 30, 2017 $ | 2017 Diluted EPS | 2016 $ | 2016 Diluted EPS |
|---|---|---|---|---|
| Net loss (GAAP)(1) | $ (52,467) | $ (0.14) | $ (427,348) | $ (1.15) |
| Adjustments: | | | | |
| Non-cash (gain) loss on derivatives | (65,481) | | 105,009 | |
| Property impairments | 209,819 | | 202,728 | |
| Gain on sale of assets | (703) | | (103,174) | |
| Total tax effect of adjustments | (54,026) | | (76,447) | |
| Total adjustments, net of tax | 89,609 | 0.24 | 128,116 | 0.34 |
| Adjusted net income (loss) (non-GAAP) | $ 37,142 | $ 0.10 | $ (299,232) | $ (0.81) |
| Weighted average diluted shares outstanding | 373,588 | | 370,327 | |
| Adjusted diluted net income (loss) per share (non-GAAP) | $ 0.10 | | $ (0.81) | |

(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 $3.9 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 November 7, 2017

| | 2017 |
|---|---|
| **Full year average production** | **238,000 to 242,000 Boe per day** |
| **Exit rate average production** | **280,000 to 290,000 Boe per day** |
| **Capital expenditures (non-acquisition)** | **$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)** | **($5.25) to ($5.75)** |
| 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.