First STACK Density Test Flows at Combined Initial Peak Rate of 21,354 Boe per Day (70% oil) from Eight Meramec Wells; Seven New Wells Flow at Average Well IP of 2,653 Boe per Day
Company Initiates Development in STACK Over-Pressured Oil Window
Bakken Enhanced Completions Yield Company Record Initial 30-Day Production Rates
Company Begins Working Down Uncompleted Bakken Wells
Annual Production Guidance Raised and Production Expense Guidance Lowered; Capital Expenditure Guidance Raised on Increased Well Completions

OKLAHOMA CITY, Nov. 2, 2016 /PRNewswire/ -- Continental Resources Inc. (NYSE: CLR) (the "Company") today reported a net loss of $109.6 million, or $0.30 per diluted share, for the quarter ended September 30, 2016.

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The Company's net loss includes certain items typically excluded by the investment community in published estimates, the result of which is often referred to as "adjusted net loss." In third quarter 2016, these typically excluded items in aggregate represented $26.8 million, or $0.08 per diluted share, of Continental's reported net loss.

EBITDAX for third quarter 2016 was $386.8 million. The Company has defined and reconciled adjusted net loss, adjusted net loss per diluted share and EBITDAX to the most directly comparable U.S. generally accepted accounting principles (GAAP) financial measures in supporting tables at the conclusion of this press release under the header Non-GAAP Financial Measures.

"We have expanded the productive footprint of STACK, SCOOP and the Bakken core, and are increasing the value of these assets with density testing and enhanced completions," commented Harold Hamm, Chairman and Chief Executive Officer. "The results of the Ludwig density test in STACK have given us confidence to begin development on acreage we have de-risked in the over-pressured oil window.

"Additionally, we brought on several excellent producers in the Bakken using enhanced completion designs, including two wells that generated CLR-record 30-day initial rates for the Bakken. This is an encouraging start as the Company begins working down its large backlog of Bakken uncompleted wells and capturing their value."

Updated 2016 Guidance Reflects Outperformance and Increased Activity

The Company now expects full-year production will range between 215,000 and 220,000 barrels of oil equivalent (Boe) per day, an increase of 5,000 Boe per day from the low end of previous guidance given in August 2016, and 15,000 to 20,000 Boe per day higher than the original guidance given in January 2016. Continental expects to exit the year with production between 205,000 and 210,000 Boe per day, reflecting a 10,000 Boe per day increase from the low end of previous guidance given in August 2016.

Continental has again improved 2016 guidance for production expense per Boe. The new range is $3.50 to $4.00 per Boe for the year, down $0.25 per Boe from previous guidance. Continued efficiencies in both the Bakken and in Oklahoma are contributing to the lower guidance.

The Company is updating guidance for non-cash equity compensation per Boe by $0.15, to a range of $0.50 to $0.70 per Boe. This brings total G&A (inclusive of cash G&A and non-cash equity compensation) down to an expected range of $1.70 to $2.30 per Boe.

The Company plans to increase the total number of gross operated well completions in 2016 by 32, relative to its previous plan. The Company now expects to complete 119 gross operated wells with first production for the year, including 29 gross operated wells in the Bakken, 33 in SCOOP, 25 in Northwest Cana JDA and 32 in STACK Meramec.

The Company plans to increase from two to four stimulation crews in North Dakota by year-end 2016. The Company now expects to end 2016 with approximately 175 gross operated uncompleted wells in the Bakken and approximately 45 gross operated uncompleted wells in Oklahoma. The projected year-end Bakken uncompleted well count of 175 excludes approximately 15 wells that will have been stimulated by year-end 2016, but not produced with first sales until 2017.

Along with increased well completion activity, Continental has increased its average working interest in both operated and non-operated wells across its plays. Consequently, the Company is increasing guidance for 2016 capital expenditures (non-acquisition) by $180 million to a new budget target of $1.1 billion. Even with the increase, the Company expects to remain cash flow positive in the fourth quarter and for the year, with excess cash flow currently planned for further reduction of debt.

2016 Updated Guidance Metrics	Updated 2016 Guidance	August 2016 Guidance
Production guidance (Boe per day)	215,000 to 220,000	210,000 to 220,000
Capital expenditures (non-acquisition)	$1.1 billion	$920 million
Production expense per Boe	$3.50 to $4.00	$3.75 to $4.25
Non-cash equity compensation per Boe	$0.50 to $0.70	$0.65 to $0.85

The Company's full 2016 guidance is stated in a table at the conclusion of this release.

Solid Third Quarter Production Results Even with Curtailed Production

Third quarter 2016 net production totaled approximately 19.1 million Boe (MMBoe), or 207,840 Boe per day, down 5% from second quarter 2016 and 9% lower than third quarter 2015. This decline, as expected, was concentrated in the Bakken play. However, third quarter 2016 production in Continental's Southern Region was a record 88,247 Boe per day. The Company curtailed Bakken production by approximately 12,000 net Boe per day during August and September due to lower commodity prices. Curtailed production was brought back online at the end of third quarter. Current total production is approximately 214,000 Boe per day.

Total net production for third quarter 2016 included 116,277 barrels of oil (Bo) per day (56% of total production) and 549.4 million cubic feet (MMcf) of natural gas per day (44% of total production). The oil and gas split for the third quarter reflected the curtailed oil production in the quarter and heightened activity in Oklahoma.

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

Boe per day	3Q 2016	2Q 2016	3Q 2015	YTD 2016	YTD 2015
North Region:					
North Dakota Bakken	99,251	114,554	123,560	114,269	124,139
Montana Bakken	8,678	10,474	12,049	9,858	13,239
Red River Units	10,475	11,075	12,110	10,949	12,574
Other	1,189	695	992	845	1,171
South Region:					
SCOOP	67,462	64,669	69,136	65,589	60,592
STACK/NW Cana	17,680	14,610	6,629	14,484	4,836
Arkoma	1,833	1,862	2,056	1,911	2,097
Other	1,272	1,384	1,746	1,375	1,982
Total	207,840	219,323	228,278	219,280	220,630

STACK: Ludwig Density Results Provide a Vision for Future Development of the Over-Pressured Oil Window

STACK/Northwest Cana production increased 21% to 17,680 Boe per day in third quarter 2016, compared with second quarter 2016.

A key milestone in the third quarter was Continental's completion of its first density test in the over-pressured oil window of

STACK. This was an eight-well Meramec density test in the Ludwig unit, including seven new wells and the original Ludwig 1-22-15XH well. The combined peak 24-hour rate from all eight Meramec wells in the unit was 21,354 Boe per day. The seven new Meramec wells flowed at a combined peak 24-hour rate of 18,572 Boe per day, or 2,653 Boe per day per well, with 70% of the production being oil. The initial Ludwig well has produced 298,000 Boe (74% oil) in 338 days and continues to flow at 815 Boe per day.

The average flowing casing pressure on the seven new wells was 1,775 psi, in line with the original Ludwig well of 1,800 psi at the time of its initial production. The density test included four wells in the Upper Meramec and four wells in the Middle Meramec, spaced 1,320 feet apart in the same zone, and offset 660 feet between zones with approximately 100 feet of vertical separation. Average lateral length for the new wells was 9,700 feet.

The Ludwig density project demonstrates the efficiency gains of multi-well pad drilling. Drilling times for the new Ludwig density wells averaged 25 days, a 36% reduction compared with the initial Ludwig well drilled in June 2015. Average completed well cost for the new Ludwig density wells was $7.8 million per well, 30% below the initial Ludwig well's cost of $11.1 million. This provides a rate of return of more than 100% for these wells at $50 per barrel WTI and $3.00 per Mcf.

"We couldn't be more pleased with the Ludwig density results," said Jack Stark, President and Chief Operating Officer. "Initial production rates were right in line with expectations, demonstrating the remarkable consistency of production and the enormous value of our leasehold in STACK. As expected, well costs came down significantly, due to pad drilling efficiencies. These efficiencies will benefit future development in STACK."

The Company currently considers approximately 47,000 net acres of its leasehold in the over-pressured oil window of STACK to be de-risked and ready for development. This includes an estimated 55 operated units that the Company expects to be developed in up to three Meramec zones and the Woodford, with typically four or more wells per zone.

The Company is currently in the process of drilling four unit developments in the over-pressured oil window including the Bernhardt, Blurton, Gillilan and Verona units in Blaine County. These unit developments will include up to five wells per zone in combinations of the Upper, Middle and Lower Meramec and Woodford zones. An additional 11 units are planned for development, and preparations are underway to facilitate ongoing unit development, including installation of additional water gathering and recycling facilities.

In addition to the Ludwig density wells, in the third quarter the Company completed the McBee 1-3H flowing 1,232 Bo and 5.3 MMcf (2,110 Boe) per day at 3,850 psi flowing casing pressure. The McBee 1-3H was drilled with a 4,760-foot lateral and is located approximately 12 miles west of the Ludwig unit.

The cost of a standalone extended lateral well in the over-pressured oil window of STACK continues to come down as efficiencies build. Continental is now targeting an average completed well cost of $8.5 million for a standalone extended-lateral well in the over-pressured oil window of STACK. This is $500,000 per well below the previous year-end 2016 target and $2.5 million below the cost for a single operated well at year-end 2015. At this targeted cost, Continental estimates a well in the over-pressured oil window should deliver more than a 100% rate of return at $50 per barrel WTI and $3.00 per Mcf. This rate of return assumes an estimated ultimate recovery (EUR) of 1.7 MMBoe per well.

During the third quarter, Continental increased its STACK Meramec leasehold by approximately 4,000 net acres to over 186,000 net acres, located primarily in Blaine, Dewey and Custer counties. Since year-end 2015, the Company has added approximately 31,000 net acres of leasehold in STACK. The Company estimates 95% of its STACK leasehold is in the over-pressured window, of which 40% is in the oil window, 40% is in the condensate window and 20% is in the gas window. The Company has 11 operated rigs in STACK, with six targeting the Meramec formation in Blaine County and five targeting the Woodford formation in the Northwest Cana JDA area in Blaine and Custer counties.

The Company also reported four new STACK Woodford completions in the NW Cana JDA in third quarter, with the NE Atteberry reporting a record 24-hour production rate for a NW Cana JDA well. The Reece Jane is still cleaning up with expectations the initial production rate will improve. Current initial 24-hour production test rates for these wells with flowing casing pressures expressed in pounds per square inch (psi) include:

- NE Atteberry 1-27-34XH flowed 19.5 MMcf per day at 6,750 psi from a 9,400-foot lateral;
- Reece Jane 1-33-4XH flowed 16.6 MMcf per day at 7,100 psi from a 9,900-foot lateral;
- Slagell 1-32-29XH flowed 12.9 MMcf per day at 4,800 psi from a 6,800-foot lateral; and
- Watson South 1-20-29XH flowed 12.4 MMcf per day at 5,100 psi from a 7,300-foot lateral.

The Company's previously announced STACK Woodford completion in NW Cana, the Lacretia 1-29-20XH, continues to produce at strong rates and pressure. The Lacretia has produced approximately 2.7 Bcf in 230 days and continues to flow at 8.8 MMcf per day, with a flowing casing pressure of 2,250 psi.

SCOOP Play: Excellent Woodford Density Results in the May Unit

In third quarter 2016, total SCOOP net production averaged 67,462 Boe per day, 4% above second quarter 2016 and slightly lower than third quarter 2015. SCOOP production represented 32% of the Company's total production in third quarter 2016. SCOOP Woodford net production averaged 60,222 Boe per day in third quarter 2016, compared with SCOOP Springer net production of 7,240 Boe per day.

Continental completed 8 net (12 gross) operated and non-operated wells in SCOOP Woodford in third quarter 2016, while operating an average of four rigs in the play.

Continental recently completed its first enhanced completion density test in the SCOOP Woodford oil window at the May unit. This was a seven-well density test, including five new wells and two parent wells in the Upper Woodford. The seven Woodford wells flowed at a combined peak 24-hour rate of 5,285 Bo and 9.6 MMcf per day (6,881 Boe per day). On a per-well basis, the seven wells average peak production was 983 Boe per day (77% oil), and the five new wells average peak production was 974 Boe per day (77% oil). Wells are spaced 775 feet apart, and average lateral length for the seven wells was 7,300 feet. Average completed well cost for the seven wells was approximately $9.3 million.

"Based on initial production, the May unit infill with enhanced completions has outperformed offset wells," said Gary Gould, Senior Vice President, Production and Resource Development. "The initial results are encouraging for future development in the SCOOP Woodford oil window."

Record Company Bakken Well Production from Enhanced Completions

Continental's Bakken production averaged 107,929 Boe per day in third quarter 2016, a decrease of 14% from second quarter 2016. Continental completed 13 net (50 gross) operated and non-operated wells in the Bakken in third quarter 2016, while operating an average of four drilling rigs in the play.

During the third quarter, the Company continued to test enhanced stimulation designs, with higher proppant volumes of up to 1,000 pounds per foot. Select initial 24-hour production test rates include:

- Brangus North 1-2H2 flowed 2,305 Bo and 1.1 MMcf (2,493 Boe) per day from a 9,900-foot lateral;
- Rath Federal 5-22H flowed 2,063 Bo and 2.0 MMcf (2,395 Boe) per day from a 13,800-foot lateral;
- Nashville 2-21H flowed 1,211 Bo and 1.2 MMcf (1,417 Boe) per day from a 12,100-foot lateral; and
- Maryland 2-16H flowed 1,073 Bo and 1.1 MMcf (1,264 Boe) per day from an 11,400-foot lateral.

The Brangus North and the Rath Federal wells, which used diverter technology, established Continental all-time record 30-day production rates for the Bakken. During the first 30 days, the Brangus North produced 51.8 MBoe (86% oil) and the Rath Federal produced 43.3 MBoe (84% oil).

"We are encouraged by the record performance from these enhanced stimulated wells," said Mr. Gould. "These are direct results of our team's success in continuing to optimize our stimulation designs, which will further improve production and profitability for our large, high rate-of-return uncompleted well inventory in 2017."

The Company has elected to begin completing its inventory of uncompleted Bakken wells. The Company is currently utilizing two stimulation crews, with plans to have a total of four stimulation crews operating by year-end 2016. With this increased activity, the Company expects to complete nine additional gross operated wells in 2016 above previous guidance. Also, an additional 15 gross operated wells will be stimulated, but will not have first sales until 2017. This will leave in inventory approximately 175 gross operated uncompleted wells at year-end 2016. This inventory has an average EUR of approximately 850,000 Boe per well, with an estimated average completion cost of $3.5 million per well. At $50 per barrel WTI and $3.00 per Mcf, the cost-forward rate of return on this incremental capital expenditure is more than 100%.

The Company's total completed well cost for a Bakken 2-mile lateral well with a standard 30-stage slick water enhanced stimulation design is approximately $6.0 million, down from $6.8 million at year-end 2015.

Financial Update

In third quarter 2016, Continental's average realized sales price, excluding the effects of derivative positions, was $37.66 per Bo and $2.02 per Mcf of gas, or $26.42 per Boe. Based on realizations without the effect of derivatives, the Company's third quarter 2016 oil differential was $7.27 per barrel below the NYMEX daily average for the period. Third quarter 2016 realized wellhead natural gas price, without the effect of derivatives, was on average $0.80 per Mcf below the average NYMEX Henry Hub benchmark price.

Production expense per Boe was $3.50 for third quarter 2016, a decrease of $0.50 per Boe from third quarter 2015. Other select operating costs and expenses for third quarter 2016 included production taxes of 6.8% of oil and natural gas sales; DD&A of $21.66 per Boe; and G&A (cash and non-cash) of $2.32 per Boe.

As of September 30, 2016, Continental's balance sheet included $19.5 million in cash and cash equivalents and $565 million of borrowings against the Company's revolving credit facility, compared to the revolver balance of $885 million at June 30, 2016. As of October 31, 2016, borrowings against the revolving credit facility had declined further to $295 million. Continental had approximately $2.45 billion in available borrowing capacity under its revolving credit facility as of October 31, 2016. The decrease in revolving credit facility borrowings in October is primarily due to the use of proceeds from the completed sale in October of non-core SCOOP leasehold for $296 million, announced in August 2016. The Company plans to borrow $624 million in November to fund the redemption of $600 million of Senior Notes, along with associated redemption premiums and accrued interest.

Capital expenditures for third quarter 2016 were $247 million, including $8 million for acquisitions. Non-acquisition capital expenditures for third quarter 2016 included $198 million in exploration and development drilling, $24 million in leasehold and seismic, and $17 million in workovers, recompletions and other.

"Continental remains on track to be cash flow positive for both the fourth quarter and for the year, inclusive of the increase in our capital expenditures budget," said John Hart, Chief Financial Officer. "We plan to continue reducing long-term debt and improving our leverage metrics through a combination of non-strategic asset sales and strengthened cash flow. Specific 2017 guidance should be announced early next year."

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,	
	2016	2015	2016	2015
Average daily production:				
Crude oil (Bbl per day)	116,277	147,472	131,873	146,975
Natural gas (Mcf per day)	549,374	484,834	524,441	441,930
Crude oil equivalents (Boe per day)	207,840	228,278	219,280	220,630
Average sales prices, excluding effect from derivatives:				
Crude oil ($/Bbl)	$37.66	$38.95	$33.51	$42.60
Natural gas ($/Mcf)	$2.02	$2.23	$1.57	$2.39
Crude oil equivalents ($/Boe)	$26.42	$29.90	$23.91	$33.18
Production expenses ($/Boe)	$3.50	$4.00	$3.66	$4.45
Production taxes (% of oil and gas revenues)	6.8%	7.6%	7.3%	7.8%
DD&A ($/Boe)	$21.66	$21.36	$22.00	$21.36
Total general and administrative expenses ($/Boe) (1)	$2.32	$2.56	$1.88	$2.38
Net loss (in thousands)	($109,621)	($82,423)	($427,348)	($213,992)
Diluted net loss per share	($0.30)	($0.22)	($1.15)	($0.58)
Adjusted net loss (non-GAAP) (in thousands) (2)	($82,853)	($43,512)	($299,232)	($28,881)
Adjusted diluted net loss per share (non-GAAP) (2)	($0.22)	($0.12)	($0.81)	($0.08)
Net cash provided by operating activities	$366,167	$498,680	$863,888	$1,415,492
EBITDAX (non-GAAP) (in thousands) (2)	$386,789	$472,221	$1,229,507	$1,558,656

(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 $1.63, $1.95, $1.31, and $1.71 for 3Q 2016, 3Q 2015, YTD 2016, and YTD 2015, respectively. Non-cash equity compensation expense per Boe was $0.69, $0.61, $0.57, and $0.67 for 3Q 2016, 3Q 2015, YTD 2016, and YTD 2015, respectively.

(2) Adjusted net loss, adjusted diluted net 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 loss, diluted net 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 loss, adjusted diluted net 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 2016 Earnings Conference Call

Continental plans to host a conference call to discuss third quarter results on Thursday, November 3, 2016, 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, November 3, 2016
Dial in:	844-309-6572
Intl. dial in:	484-747-6921
Pass code:	69753165

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:	69753165

Continental plans to publish a third quarter 2016 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on November 3, 2016.

Upcoming Conferences

Members of Continental's management team will be participating in the following upcoming investment conferences:

November 17-18, 2016 – Bank of America Merrill Lynch Global Energy Conference, Miami
November 29, 2016 – Capital One STACK/SCOOP Day, New York
December 7-8, 2016 – Capital One 11th Annual Energy Conference, New Orleans

Presentation materials for all conferences listed above will be available on the Company's website at www.CLR.com on or prior to the day of the presentations.

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 one of the largest producers in the nation's premier oil field, the Bakken play of North Dakota and Montana. The Company also has leading positions in Oklahoma, including its SCOOP Woodford and SCOOP Springer discoveries and the STACK and Northwest Cana 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 ended December 31, 2015, 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 September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Revenues:	In thousands, except per share data			
Crude oil and natural gas sales	$ 505,892	$ 628,457	$ 1,435,194	$ 2,001,151
Gain (loss) on crude oil and natural gas derivatives, net	15,668	46,527	(24,477)	74,545
Crude oil and natural gas service operations	4,639	7,685	19,867	28,991
Total revenues	526,199	682,669	1,430,584	2,104,687
Operating costs and expenses:				
Production expenses	67,022	84,036	219,745	268,712
Production taxes and other expenses	34,583	47,682	104,216	157,589
Exploration expenses	3,987	232	8,726	14,680
Crude oil and natural gas service operations	2,605	4,059	9,224	15,045
Depreciation, depletion, amortization and accretion	414,671	448,809	1,320,423	1,288,278
Property impairments	57,689	96,697	202,728	321,130
General and administrative expenses	44,389	53,798	113,043	143,368
Net gain on sale of assets and other	(5,564)	(288)	(104,690)	(22,930)
Total operating costs and expenses	619,382	735,025	1,873,415	2,185,872
Loss from operations	(93,183)	(52,356)	(442,831)	(81,185)
Other income (expense):				
Interest expense	(82,074)	(79,399)	(244,949)	(232,904)
Other	360	588	1,178	1,474
	(81,714)	(78,811)	(243,771)	(231,430)
Loss before income taxes	(174,897)	(131,167)	(686,602)	(312,615)
Benefit for income taxes	(65,276)	(48,744)	(259,254)	(98,623)
Net loss	$ (109,621)	$ (82,423)	$ (427,348)	$ (213,992)
Basic net loss per share	$ (0.30)	$ (0.22)	$ (1.15)	$ (0.58)
Diluted net loss per share	$ (0.30)	$ (0.22)	$ (1.15)	$ (0.58)

Continental Resources Inc. and Subsidiaries

Unaudited Condensed Consolidated Balance Sheets

	September 30, 2016	December 31, 2015
Assets	In thousands	
Current assets	$ 750,875	$ 822,339
Net property and equipment [1]	13,094,683	14,063,328
Other noncurrent assets	19,694	34,141
Total assets	$ 13,865,252	$ 14,919,808
Liabilities and shareholders' equity		
Current liabilities	$ 802,350	$ 923,028
Long-term debt, net of current portion	6,830,141	7,115,644
Other noncurrent liabilities	1,972,063	2,212,236
Total shareholders' equity	4,260,698	4,668,900
Total liabilities and shareholders' equity	$ 13,865,252	$ 14,919,808

(1) Balance is net of accumulated depreciation, depletion and amortization of $7.35 billion and $6.45 billion as of September 30, 2016 and December 31, 2015, respectively.

Continental Resources Inc. and Subsidiaries

Unaudited Condensed Consolidated Statements of Cash Flows

	Three months ended September 30,				Nine months e
In thousands	2016		2015		2016
Net loss	$	(109,621)	$	(82,423)	$ (427,348)
Adjustments to reconcile net loss to net cash provided by operating activities:					
Non-cash expenses		415,690		465,606	1,318,720
Changes in assets and liabilities		60,098		115,497	(27,484)
Net cash provided by operating activities		366,167		498,680	863,888
Net cash used in investing activities		(32,427)		(634,396)	(550,221)
Net cash (used in) provided by financing activities		(330,802)		132,031	(305,641)
Effect of exchange rate changes on cash		(2)		(4,818)	7
Net change in cash and cash equivalents		2,936		(8,503)	8,033
Cash and cash equivalents at beginning of period		16,560		25,458	11,463
Cash and cash equivalents at end of period	$	19,496	$	16,955	$ 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, and non-cash equity compensation expense. EBITDAX is not a measure of net income 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 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 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.

In thousands	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Net loss	$ (109,621)	$ (82,423)	$ (427,348)	$ (213,992)
Interest expense	82,074	79,399	244,949	232,904
Benefit for income taxes	(65,276)	(48,744)	(259,254)	(98,623)
Depreciation, depletion, amortization and accretion	414,671	448,809	1,320,423	1,288,278
Property impairments	57,689	96,697	202,728	321,130
Exploration expenses	3,987	232	8,726	14,680
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	(15,237)	(46,527)	21,768	(74,545)
Total cash received on derivatives, net	5,274	11,917	83,241	48,534
Non-cash (gain) loss on derivatives, net	(9,963)	(34,610)	105,009	(26,011)
Non-cash equity compensation	13,228	12,861	34,274	40,290
EBITDAX (non-GAAP)	$ 386,789	$ 472,221	$ 1,229,507	$ 1,558,656

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, 2016	2015	Nine months ended September 30, 2016	2015
Net cash provided by operating activities	$ 366,167	$ 498,680	$ 863,888	$ 1,415,492
Current income tax provision (benefit)	(10)	12	2	22
Interest expense	82,074	79,399	244,949	232,904
Exploration expenses, excluding dry hole costs	3,960	51	8,493	6,497
Gain on sale of assets, net	6,158	288	103,174	22,930
Tax benefit (deficiency) from stock-based compensation	(9,460)	13,177	(9,460)	13,177
Other, net	(2,002)	(3,889)	(9,023)	(8,023)
Changes in assets and liabilities	(60,098)	(115,497)	27,484	(124,343)
EBITDAX (non-GAAP)	$ 386,789	$ 472,221	$ 1,229,507	$ 1,558,656

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 and gains and losses on asset sales. 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 September 30,			
	2016		2015	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net loss (GAAP)	$(109,621)	$ (0.30)	$ (82,423)	$ (0.22)
Adjustments:				
Non-cash gain on derivatives	(9,963)		(34,610)	
Property impairments	57,689		96,697	
Gain on sale of assets	(6,158)		(288)	
Total tax effect of adjustments	(14,800)		(22,888)	
Total adjustments, net of tax	26,768	0.08	38,911	0.10
Adjusted net loss (non-GAAP)	$ (82,853)	$ (0.22)	$ (43,512)	$ (0.12)
Weighted average diluted shares outstanding	370,483		369,599	
Adjusted diluted net loss per share (non-GAAP)	$ (0.22)		$ (0.12)	

	Nine months ended September 30,			
	2016		2015	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net loss (GAAP)	$(427,348)	$ (1.15)	$(213,992)	$ (0.58)
Adjustments:				
Non-cash (gain) loss on derivatives	105,009		(26,011)	
Property impairments	202,728		321,130	
Gain on sale of assets	(103,174)		(22,930)	
Total tax effect of adjustments	(76,447)		(87,078)	
Total adjustments, net of tax	128,116	0.34	185,111	0.50
Adjusted net loss (non-GAAP)	$(299,232)	$ (0.81)	$ (28,881)	$ (0.08)
Weighted average diluted shares outstanding	370,327		369,499	
Adjusted diluted net loss per share (non-GAAP)	$ (0.81)		$ (0.08)	

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.

2016 Guidance

As of November 2, 2016 [1]

	2016
Full year average production	215,000 - 220,000 Boe per day
Capital expenditures (non-acquisition)	$1.1 billion
Operating Expenses:	
Production expense per Boe	$3.50 - $4.00
Production tax (% of oil & gas revenue)	6.75% - 7.25%
Cash G&A expense per Boe[2]	$1.20 - $1.60
Non-cash equity compensation per Boe	$0.50 - $0.70
DD&A per Boe	$20.00 - $22.00
Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	($7.00) - ($8.00)
Henry Hub natural gas (per Mcf)	$0.00 - ($0.65)
Income tax rate	38%
Deferred taxes	90% - 95%

(1) Bolded items denote a guidance revision from the previous disclosure provided on August 3, 2016

(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 $1.70 to $2.30 per Boe.

To view the original version on PR Newswire, visit:http://www.prnewswire.com/news-releases/continental-resources-reports-third-quarter-2016-results-300356204.html

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