NEWS RELEASE

CONTINENTAL RESOURCES REPORTS FOURTH QUARTER AND FULL-YEAR 2015 RESULTS

Three New STACK Completions Further Demonstrate the Potential of Continental's Over-Pressured Meramec Assets; Largest New Well Produces 3,508 Barrels of Oil Equivalent Per Day

Enhanced Completions in SCOOP Woodford Condensate Lift Early Production Rates by 30% to 35% and Estimated Ultimate Recoveries by 15% to 2.0 Million Barrels of Oil Equivalent

Third SCOOP Woodford Density Pilot Flows at Combined Peak Rates of 52 Million Cubic Feet of Natural Gas and 4,980 Barrels of Oil per Day from Seven New Wells

Oklahoma City, February 24, 2016 – Continental Resources, Inc. (NYSE: CLR) (the "Company") today announced fourth quarter and full-year 2015 operating and financial results. Continental reported a net loss of $139.7 million, or $0.38 per diluted share, for the quarter ended December 31, 2015. Adjusted net loss for fourth quarter 2015 was $86.6 million, or $0.23 per diluted share.

For full-year 2015, the Company reported a net loss of $353.7 million, or $0.96 per diluted share. Adjusted net loss for full-year 2015 was $115.5 million, or $0.31 per diluted share.

EBITDAX for fourth quarter 2015 was $420.2 million, contributing to full-year 2015 EBITDAX of $1.98 billion. Definitions and reconciliations of adjusted net loss, adjusted earnings per share and EBITDAX to the most directly comparable U.S. generally accepted accounting principles (GAAP) financial measures can be found in the supporting tables at the conclusion of this press release.

"Our teams did an outstanding job in 2015 adjusting to market changes and working to align capital expenditures with cash flow. For 2016, we will remain patient and disciplined in our activities while striving to enhance shareholder value through continued improvements in our core plays, including our newest addition, the over-pressured STACK," commented Harold Hamm, Continental's Chairman and Chief Executive Officer.

He noted that three new wells in Oklahoma's STACK play further demonstrate the outstanding potential of Continental's leasehold position. "The Boden well was a significant step-out in southern Blaine County, and all three recent completions support our view of the upside of the over-pressured STACK Meramec formation," Mr. Hamm said.

"Our SCOOP Woodford team has engineered a step-change increase in 90-day and 180-day production rates by applying enhanced completion techniques using increased proppant loading," he said. "This has translated into higher estimated ultimate recoveries and made SCOOP an even more valuable growth platform."

Production

Fourth quarter 2015 net production totaled 20.7 million barrels of oil equivalent (Boe), or 224,900 Boe per day, down slightly from third quarter 2015 and 16% higher than fourth quarter 2014. February 2016 production is expected to be approximately 225,000 Boe per day.

Total net production for the fourth quarter included 145,600 barrels of oil (Bo) per day (65% of production) and 476.2 million cubic feet (MMcf) of natural gas per day (35% of production). Full-year 2015 production averaged 221,700 Boe per day, an increase of 27% compared with full-year 2014.

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

Boe per day	4Q 2015	3Q 2015	4Q 2014	FY 2015	FY 2014
North Region:					
North Dakota Bakken	125,583	123,560	115,137	124,503	100,050
Montana Bakken	10,772	12,049	15,646	12,617	14,665
Red River Units	11,654	12,110	13,259	12,342	13,815
Other	902	992	690	1,103	800
South Region:					
SCOOP	64,534	69,136	40,403	61,586	35,128
NW Cana/STACK	7,709	6,629	3,780	5,560	4,906
Arkoma	2,124	2,056	2,318	2,104	2,493
Other	1,658	1,746	2,223	1,900	2,332
Total	224,936	228,278	193,456	221,715	174,189

Impressive New STACK Results Include 16-Mile Step-Out Well

The Company's new STACK completions were the Boden 1-15-10XH, the Compton 1-2-35XH and the Blurton 1-7-6XH, all extended lateral tests targeting the over-pressured Meramec formation in Blaine County.

The Boden is a significant step-out test located 16 miles southwest of Continental's first STACK well, the Ludwig 1-22-15XH. The Boden flowed at an impressive 24-hour initial production rate of 1,000 Bo and 15 MMcf of natural gas (3,508 Boe) from a 9,800-foot lateral. It is the Company's deepest test of the Meramec reservoir to date, with the lateral section of the well positioned at an average vertical depth of 12,550 feet. Through the first 80 days of production, the Boden has continued to exhibit strong flowing casing pressure of more than 5,000 psi on a 20/64" choke.

The Compton and Blurton wells were closer step-out tests located five miles southwest and three miles northwest, respectively, of the Ludwig. The Compton flowed at an initial 24-hour production rate of 1,817 Bo and 4.4 MMcf of natural gas (2,547 Boe) from a 9,800-foot lateral. The Blurton flowed at an initial 24-hour production rate of 1,818 Bo and 3.1 MMcf of natural gas (2,328 Boe) from a 9,600-foot lateral.

"Our over-pressured Meramec wells in STACK are delivering some of the highest returns in the Company. We clearly have another high impact, long-term platform for growth underlying our 155,000 net acres of leasehold in STACK," said Jack Stark, Continental's President and Chief Operating Officer. "The exceptional performance of these new wells supports our observation that over-pressured STACK wells produce on average three times more volume than wells in the normally-pressured STACK in their first 90 days, when normalized for a 9,800' foot lateral. This is significant, as almost all of Continental's STACK acreage is located in the over-pressured window."

Based on early production from recent Continental completions and other non-operated wells in the over-pressured oil window, the Company is estimating an average estimated ultimate recovery (EUR) of 1.7 MMBoe per well. Continental is targeting a completed operated well cost of $10 million for a 9,800-foot lateral well, which would generate a 55% rate of return at $40 per barrel WTI and $2.25 per thousand cubic feet (Mcf) of natural gas.

The Company plans to average four-to-five operated drilling rigs in STACK in 2016, which would enable it to drill approximately 15 net (25 gross) operated wells and complete approximately nine net (15 gross) operated wells this year in the play. Continental's STACK leasehold is primarily in Blaine, Dewey and Custer counties, and the Company anticipates more than 70% of it will be held by production by year-end 2016.

SCOOP Fourth Quarter Production Increases 60% Year over Year

In fourth quarter 2015, total SCOOP net production averaged 64,500 Boe per day, a 60% increase compared with the fourth quarter of 2014, and a 7% decrease sequentially compared with third quarter 2015, reflecting reduced completion activity. SCOOP production represented 29% of the Company's total production in fourth quarter 2015, compared with 21% of Company production for fourth quarter 2014.

Of total SCOOP production, SCOOP Woodford net production averaged 54,100 Boe per day in fourth quarter 2015, or 84% of the total. SCOOP Springer net production averaged 10,400 Boe per day.

Continental completed eight net (38 gross) operated and non-operated wells in SCOOP in fourth quarter 2015, while operating an average of seven rigs in the play. Of these, the Company completed 7.5 net (36 gross) wells targeting the Woodford formation and 0.5 net (two gross) wells targeting the Springer formation.

For full-year 2015, Continental completed 74 net (204 gross) operated and non-operated SCOOP wells. These included 54 net (175 gross) wells targeting the Woodford, and 20 net (29 gross) wells targeting the Springer.

For all Oklahoma plays, Continental ended 2015 with approximately 35 gross operated wells drilled and uncompleted (DUCs) and plans to end 2016 with approximately 50 gross operated DUCs. The Company noted that its DUC inventory may also include wells that are drilled and completed, but not yet producing to sales.

SCOOP Woodford Enhanced Completions Deliver Step-Change Production Improvement

Continental has tested enhanced completions, primarily involving larger proppant volumes, on 15 SCOOP Woodford condensate wells. All are producing in excess of the Company's standard type curve based on a 1.7 MMBoe EUR for a 7,500' lateral. Enhanced completions have increased initial 90-day and 180-day production rates 30% to 35%, compared with offset wells. Based on the performance of the enhanced completed wells, the Company is increasing its SCOOP Woodford condensate EUR by 15% to 2.0 MMBoe per well.

The incremental cost for the large enhanced completions being done currently is approximately $400,000, bringing the completed well cost for these wells to approximately $9.9 million. This cost is expected to decline during 2016 to a targeted well cost of $9.6 million. At a target cost of $9.6 million, these wells generate a 25% ROR based on $40 per barrel WTI and $2.25 per Mcf of gas.

"We are encouraged by the results from our enhanced completions in SCOOP, and we continue to work to optimize our stimulation designs," said Gary Gould, Senior Vice President of Production and Resource Development. "Our new type curves were built on data from initial enhanced completions with at least 90 days of production, and this well set had completion designs that averaged approximately 1,100 pounds of proppant per foot. More recently we've applied higher proppant concentrations averaging approximately 1,500 pounds per foot, and we're seeing even higher early production from these higher sand volumes."

SCOOP Woodford Density Test: Vanarkel Production Beats Enhanced Type Curve

Continental's Vanarkel density project came online in fourth quarter 2015. Vanarkel involved seven gross (four net) wells that were stimulated with enhanced completions averaging approximately 1,500 pounds per foot of proppant. Early initial production for the Vanarkel wells is beating the Company's updated SCOOP Woodford condensate type curve for enhanced completions. The wells flowed at an average total combined peak production rate of 52.4 MMcf and 4,980 Bo per day, or a total combined 13,713 Boe per day. Average peak production was 1,959 Boe per day per well in the project. Vanarkel production is 36% oil, comparable to the nearby Honeycutt density test.

The Vanarkel project was the Company's third dual-level density pilot in the SCOOP Woodford condensate window, consisting of wells in the upper and lower Woodford, spaced 660 feet apart between well bores with approximately 100 feet of vertical separation. Average lateral length for the new Vanarkel wells was 7,400 feet.

SCOOP Springer

Continental participated in completing two notable non-operated wells targeting the Springer formation in fourth quarter 2015. The first non-operated well flowed at a rate of approximately 2,100 Boe (88% oil) per day, and the second was announced by its operator as flowing at a rate of 1,007 Boe (89% oil) per day.

Bakken DUC Inventory Growing in 2016

Continental's Bakken production averaged 136,400 Boe per day in fourth quarter 2015, a slight increase over third quarter 2015.

The Company completed and initiated first sales for 22 net (105 gross) operated and non-operated Bakken wells during fourth quarter 2015, compared with a total 171 net (638 gross) operated and non-operated Bakken wells for full-year 2015. Continental's operated wells with initial production in fourth quarter 2015 involved wells that had been previously drilled and completed, but not actively produced with first sales until the fourth quarter.

In 2015, the Bakken team doubled capital efficiency and cut finding costs in half. This was accomplished through a combination of inventory high-grading, cost reductions and operating efficiencies. The Company reduced average drilling time for spud-to-total-depth (TD) by 23% and average drilling cost by 33%, compared to fourth quarter 2014. The average spud-to-TD time in fourth quarter 2015 was 13.4 days for a well with a two-mile lateral, down from 17.4 days for fourth quarter 2014.

In 2016, the Bakken drilling program will continue to focus on high rate-of-return areas in McKenzie and Mountrail counties, targeting wells with an average EUR of 900,000 Boe per well. Based on the higher EUR and a lower targeted completed well cost of $6.7 million per well, the Company expects capital efficiency to increase 17% and finding cost to decrease 15% in 2016.

Given its plans to defer most Bakken completions in 2016, Continental expects to increase its Bakken DUC inventory to approximately 195 gross operated DUCs at year-end 2016. The year-end 2016 DUC inventory represents a high-graded inventory with an average EUR per well of approximately 850,000 Boe. At year-end 2015, the Company's Bakken DUC inventory was approximately 135 gross operated DUCs.

The Company currently has four operated drilling rigs in the North Dakota Bakken and plans to maintain this level through year end. The Company currently has no stimulation crews deployed in the Bakken.

Financial Update

In fourth quarter 2015, Continental's average realized sales price excluding the effects of derivative positions was $34.23 per barrel of oil and $2.07 per Mcf of gas, or $26.57 per Boe. Based on realizations without the effect of derivatives, the Company's fourth quarter 2015 oil differential was $7.71 per barrel below the NYMEX daily average for the period. The fourth quarter 2015 realized wellhead natural gas price was on average $0.20 per Mcf below the average NYMEX Henry Hub benchmark price.

Production expense per Boe was $3.86 for fourth quarter 2015, a decrease of $1.45 per Boe from fourth quarter 2014. Other select operating costs and expenses for fourth quarter 2015 included production taxes of 7.8% of oil and natural gas sales; DD&A of $22.20 per Boe; and G&A (cash and non-cash) of $2.24 per Boe. On a full-year basis, these expense categories were within or better than guidance.

As of December 31, 2015, Continental's balance sheet included $11.5 million in cash and cash equivalents and $853 million of borrowings against the Company's revolving credit facility. Continental had approximately $1.9 billion in available borrowing capacity under its revolving credit facility as of December 31, 2015, and approximately $1.9 billion remains available at this time. The Company's revolver is unsecured, and there are no terms in the facility that would mandate collateral or a borrowing base calculation coming back into place. The revolver's sole financial covenant is a net debt to total capitalization ratio of no greater than 0.65, and as of December 31, 2015, the Company's net debt to total capitalization ratio was 0.58. Under the terms of the credit agreement, the calculation of total capitalization specifically excludes any non-cash impairment charges incurred after June 30, 2014.

Non-acquisition capital expenditures for fourth quarter 2015 totaled $394.0 million, including $343.6 million in exploration and development drilling, $32.8 million in leasehold and seismic and $17.6 million in workovers, recompletions and other. Acquisition capital expenditures totaled $17.8 million for fourth quarter 2015.

Full-year 2015 non-acquisition capital expenditures totaled $2.5 billion, in line with commentary made on the third quarter 2015 earnings call. Acquisition capital expenditures totaled $61.0 million for the year.

John Hart, Continental's Chief Financial Officer, commented, "We were very pleased to finish the year $200 million under our $2.7 billion budget, while still growing production 27% year-over-year. This speaks to the quality of our operating teams and assets. Looking ahead, our strategy is to stay focused on cash flow neutrality and maintaining our financial strength. We have ample liquidity with no near-term debt maturities."

Continental's 2016 guidance remains as announced on January 26, 2016 and can be found at the conclusion of this press release.

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

	Three months ended December 31,		Year ended December 31,	
	2015	2014	2015	2014
Average daily production:				
Crude oil (Bbl per day)	145,576	136,972	146,622	121,999
Natural gas (Mcf per day)	476,160	338,907	450,558	313,137
Crude oil equivalents (Boe per day)	224,936	193,456	221,715	174,189
Average sales prices, excluding effect from derivatives:				
Crude oil ($/Bbl)	$34.23	$61.53	$40.50	$81.26
Natural gas ($/Mcf)	$2.07	$4.36	$2.31	$5.40
Crude oil equivalents ($/Boe)	$26.57	$51.11	$31.48	$66.53
Production expenses ($/Boe)	$3.86	$5.31	$4.30	$5.58
Production taxes (% of oil and gas revenues)	7.8%	8.3%	7.8%	8.2%
DD&A ($/Boe)	$22.20	$22.39	$21.57	$21.51
General and administrative expenses ($/Boe)	$1.68	$2.00	$1.70	$2.06
Non-cash equity compensation ($/Boe)	$0.56	$0.85	$0.64	$0.86
Net income (loss) (in thousands)	($139,677)	$114,048	($353,668)	$977,341
Diluted net income (loss) per share	($0.38)	$0.31	($0.96)	$2.64
Adjusted net income (loss) (in thousands) (1)	($86,644)	$420,770	($115,525)	$1,271,171
Adjusted diluted net income (loss) per share (1)	($0.23)	$1.14	($0.31)	$3.43
EBITDAX (in thousands) (1)	$420,239	$1,185,071	$1,978,896	$3,776,051

(1) 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 operating cash flows as determined in accordance with U.S. GAAP. Further information about these non-GAAP financial measures as well as reconciliations of adjusted net income (loss), adjusted diluted net income (loss) per share, and EBITDAX to the most directly comparable U.S. GAAP financial measures are provided subsequently under the header *Non-GAAP Financial Measures*.

Fourth Quarter and Full-Year Earnings Conference Call

Continental plans to host a conference call to discuss fourth quarter and full-year results on Thursday, February 25, 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, February 25, 2016
Dial in:	855-291-6799
Intl. dial in:	315-625-3058
Pass code:	96302633

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:	96302633

Continental plans to publish a fourth quarter and full-year 2015 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on February 25, 2016.

Upcoming Conferences

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

March 22, 2016 - Scotia Howard Weil 44th Annual Energy Conference, New Orleans

About Continental Resources

Continental Resources (NYSE: CLR) is a top 10 independent oil producer in the U.S. Lower 48 and a leader in America's energy renaissance. Based in Oklahoma City, Continental is the largest leaseholder and 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 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 2016, the Company will celebrate 49 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, 2014, and once filed, 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
Consolidated Statements of Income (Loss)

	Three months ended December 31,		Year ended December 31,	
	2015	2014	2015	2014
	In thousands, except per share data			
Revenues:				
Crude oil and natural gas sales	$ 551,380	$ 902,323	$ 2,552,531	$ 4,203,022
Gain on derivative instruments, net	16,540	387,958	91,085	559,759
Crude oil and natural gas service operations	7,560	7,419	36,551	38,837
Total revenues	575,480	1,297,700	2,680,167	4,801,618
Operating costs and expenses:				
Production expenses	80,185	93,691	348,897	352,472
Production taxes and other expenses	43,048	77,034	200,637	349,760
Exploration expenses	4,732	20,535	19,413	50,067
Crude oil and natural gas service operations	2,292	3,481	17,337	21,871
Depreciation, depletion, amortization and accretion	460,778	395,260	1,749,056	1,358,669
Property impairments	81,001	393,803	402,131	616,888
General and administrative expenses	46,478	50,220	189,846	184,655
Gain on sale of assets, net	(218)	(1,552)	(23,149)	(600)
Total operating costs and expenses	718,296	1,032,472	2,904,168	2,933,782
Income (loss) from operations	(142,816)	265,228	(224,001)	1,867,836
Other income (expense):				
Interest expense	(80,175)	(74,200)	(313,079)	(283,928)
Loss on extinguishment of debt	-	-	-	(24,517)
Other	520	702	1,995	2,647
	(79,655)	(73,498)	(311,084)	(305,798)
Income (loss) before income taxes	(222,471)	191,730	(535,085)	1,562,038
Provision (benefit) for income taxes	(82,794)	77,682	(181,417)	584,697
Net income (loss)	$ (139,677)	$ 114,048	$ (353,668)	$ 977,341
Basic net income (loss) per share	$ (0.38)	$ 0.31	$ (0.96)	$ 2.65
Diluted net income (loss) per share	$ (0.38)	$ 0.31	$ (0.96)	$ 2.64

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2015	December 31, 2014
Assets	*In thousands*	
Current assets	$ 822,339	$ 1,389,601
Net property and equipment [(1)]	14,063,328	13,635,852
Other noncurrent assets [(2)]	34,141	50,580
Total assets	$ 14,919,808	$ 15,076,033
Liabilities and shareholders' equity		
Current liabilities [(3)]	$ 923,028	$ 1,806,664
Long-term debt, net of current portion [(2)]	7,115,644	5,926,800
Other noncurrent liabilities [(3)]	2,212,236	2,374,725
Total shareholders' equity	4,668,900	4,967,844
Total liabilities and shareholders' equity	$ 14,919,808	$ 15,076,033

(1) Balance is net of accumulated depreciation, depletion and amortization of $6.45 billion and $4.65 billion as of December 31, 2015 and December 31, 2014, respectively.

(2) Balances at December 31, 2014 have been retroactively adjusted to reflect the Company's June 2015 adoption of Accounting Standards Update 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs, which resulted in the reclassification of $69.0 million of unamortized debt issuance costs at December 31, 2014 from "Other noncurrent assets" to a reduction of "Long-term debt, net of current portion".

(3) Balances at December 31, 2014 have been retroactively adjusted to reflect the Company's December 2015 adoption of Accounting Standards Update 2015-17, Balance Sheet Classification of Deferred Taxes, which resulted in the reclassification of $145.3 million of deferred tax liabilities at December 31, 2014 from "Current liabilities" to "Other noncurrent liabilities".

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

In thousands	Three months ended December 31, 2015	Three months ended December 31, 2014	Year ended December 31, 2015	Year ended December 31, 2014
Net income (loss)	$ (139,677)	$ 114,048	$ (353,668)	$ 977,341
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash expenses	477,006	995,960	1,982,147	2,505,053
Changes in assets and liabilities	104,280	(32,144)	228,622	(126,679)
Net cash provided by operating activities	441,609	1,077,864	1,857,101	3,355,715
Net cash used in investing activities	(448,548)	(1,361,139)	(3,046,247)	(4,587,399)
Net cash provided by financing activities	3,492	155,498	1,187,189	1,227,715
Effect of exchange rate changes on cash	(2,045)	(132)	(10,961)	(132)
Net change in cash and cash equivalents	(5,492)	(127,909)	(12,918)	(4,101)
Cash and cash equivalents at beginning of period	16,955	152,290	24,381	28,482
Cash and cash equivalents at end of period	$ 11,463	$ 24,381	$ 11,463	$ 24,381

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 or operating cash flows as determined by U.S. GAAP.

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

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

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

In thousands	Three months ended December 31, 2015	Three months ended December 31, 2014	Year ended December 31, 2015	Year ended December 31, 2014
Net income (loss)	$ (139,677)	$ 114,048	$ (353,668)	$ 977,341
Interest expense	80,175	74,200	313,079	283,928
Provision (benefit) for income taxes	(82,794)	77,682	(181,417)	584,697
Depreciation, depletion, amortization and accretion	460,778	395,260	1,749,056	1,358,669
Property impairments	81,001	393,803	402,131	616,888
Exploration expenses	4,732	20,535	19,413	50,067
Impact from derivative instruments:				
Total gain on derivatives, net	(16,540)	(387,958)	(91,085)	(559,759)
Total cash received on derivatives, net	21,019	482,567	69,553	385,350
Non-cash (gain) loss on derivatives, net	4,479	94,609	(21,532)	(174,409)
Non-cash equity compensation	11,545	14,934	51,834	54,353
Loss on extinguishment of debt	-	-	-	24,517
EBITDAX	$ 420,239	$ 1,185,071	$ 1,978,896	$ 3,776,051

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 December 31, 2015	Three months ended December 31, 2014	Year ended December 31, 2015	Year ended December 31, 2014
Net cash provided by operating activities	$ 441,609	$ 1,077,864	$ 1,857,101	$ 3,355,715
Current income tax provision (benefit)	2	(2,258)	24	20
Interest expense	80,175	74,200	313,079	283,928
Exploration expenses, excluding dry hole costs	4,535	5,998	11,032	26,388
Gain on sale of assets, net	218	1,552	23,149	600
Excess tax benefit from stock-based compensation	-	-	13,177	-
Other, net	(2,020)	(4,429)	(10,044)	(17,279)
Changes in assets and liabilities	(104,280)	32,144	(228,622)	126,679
EBITDAX	$ 420,239	$ 1,185,071	$ 1,978,896	$ 3,776,051

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 on a recurring, comparable basis from period to period. In addition, management believes these measures are used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis without regard to an entity's specific derivative portfolio, impairment methodologies, and property dispositions. Adjusted earnings and adjusted earnings per share should not be considered in isolation or as a substitute for earnings or diluted earnings per share as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies. The following tables reconcile earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

	Three Months Ended December 31,			
	2015		2014	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (loss) (GAAP)	$ (139,677)	$ (0.38)	$ 114,048	$ 0.31
Adjustments, net of tax:				
Non-cash loss on derivatives, net	2,777	0.01	59,603	0.16
Property impairments	50,391	0.14	248,096	0.67
Gain on sale of assets, net	(135)	-	(977)	-
Adjusted net income (loss) (Non-GAAP)	$ (86,644)	$ (0.23)	$ 420,770	$ 1.14
Weighted average diluted shares outstanding	369,662		370,545	
Adjusted diluted net income (loss) per share (Non-GAAP)	$ (0.23)		$ 1.14	

	Year Ended December 31,			
	2015		2014	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (loss) (GAAP)	$ (353,668)	$ (0.96)	$ 977,341	$ 2.64
Adjustments, net of tax:				
Non-cash gain on derivatives, net	(13,350)	(0.03)	(109,878)	(0.30)
Property impairments	265,842	0.72	388,640	1.05
Gain on sale of assets, net	(14,349)	(0.04)	(378)	-
Loss on extinguishment of debt	-	-	15,446	0.04
Adjusted net income (loss) (Non-GAAP)	$ (115,525)	$ (0.31)	$ 1,271,171	$ 3.43
Weighted average diluted shares outstanding	369,540		370,758	
Adjusted diluted net income (loss) per share (Non-GAAP)	$ (0.31)		$ 3.43	

Continental Resources, Inc.
2016 Guidance
As of February 24, 2016

	2016
Full year average production	200,000 Boe per day
Capital expenditures (non-acquisition)	$920 million
Operating Expenses:	
Production expense per Boe	$4.25 to $4.75
Production tax (% of oil & gas revenue)	6.75% to 7.25%
G&A expense per Boe	$1.25 to $1.75
Non-cash equity compensation per Boe	$0.65 to $0.85
DD&A per Boe	$20.00 to $22.00
Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	($7.00) to ($9.00)
Henry Hub natural gas (per Mcf)	$0.00 to ($0.65)
Income tax rate	38%
Deferred taxes	90% to 95%