Production Increases to 206,829 Barrels of Oil Equivalent per Day
Non-Acquisition Capital Expenditures $57 Million below Budget
Cash Costs per Boe Reduced 23% below Full-Year 2014 Average
Drilling and Completion Costs Currently 15% below Year-End 2014
10-Well SCOOP Woodford Density Pilot Flows at Combined Peak Production Rates of 147 Million Cubic Feet of Natural Gas and 3,240 Barrels of Oil Per Day
4-Well SCOOP Springer Density Pilot Flows at Combined Peak Production Rates of 4.4 Million Cubic Feet of Natural Gas and 3,123 Barrels of Oil Per Day

OKLAHOMA CITY, May 6, 2015 /PRNewswire/ -- Continental Resources Inc. (NYSE: CLR) (Continental or the Company) today announced first quarter 2015 operating and financial results.

Logo - http://photos.prnewswire.com/prnh/20120327/DA76602LOGO

Continental reported a net loss of $132.0 million, or $0.36 per diluted share, for the first quarter of 2015. Adjusted net loss for the first quarter of 2015 was $33.8 million, or $0.09 per diluted share.

EBITDAX for the first quarter of 2015 was $439.4 million, compared with EBITDAX of $775.4 million for the first quarter of 2014, reflecting the decline in average commodity prices since June 2014. 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 have done an outstanding job making the necessary adjustments to achieve our 2015 goals of aligning capital expenditures with cash flow by mid-year, reduce expenses across the board, and maximize returns on every dollar we spend. We're proud of Continental's early 2015 performance and discipline," said Harold Hamm, Chairman and Chief Executive Officer.

"Looking ahead, U.S. oil production is starting to roll over, as anticipated. Given the depth and quality of our assets, Continental is well-positioned to resume growing cash flow and earnings when the oil price environment improves. We remain encouraged by the outlook for the second half of the year and for 2016."

Improving Returns from Declining Costs

Continental's drilling and completion costs for most operated wells have declined approximately 15% since the end of 2014, primarily due to lower service costs. This is ahead of expectations. The Company's estimated drilling and completion costs for operated wells in the Bakken have decreased to $8.2 million per well, based on a two-mile lateral with an enhanced completion design, compared with $9.6 million per well at year-end 2014. Estimated drilling and completion costs for operated Woodford wells in the South Central Oklahoma Oil Province (SCOOP) have decreased to $10.4 million, based on a 7,500-foot lateral, compared with $12.2 million per well at year-end 2014.

Looking forward, the Company now expects to realize service cost reductions of up to 20% by mid-year and further savings from drilling and completion efficiencies. As an example, Continental recently set a new Company record in the Bakken by drilling the two-mile lateral portion of a well in three days, nearly four days faster than its average time to drill a lateral in the basin. This same well was drilled from spud to total depth in 13 days, nearly five days faster than the Company's average spud-to-TD time in the Bakken. So far this year, Continental has drilled eight wells to total depth in 14 days or less, raising the Company's technical bar as overall drilling efficiencies continue to improve.

Production

First quarter 2015 net production totaled 18.6 million barrels of oil equivalent (Boe), or 206,829 Boe per day, a sequential increase of 7% from fourth quarter 2014 and 36% higher than first quarter 2014. Total net production for the first quarter included 143,511 barrels of oil (Bo) per day (69% of production) and 379.9 million cubic feet (MMcf) of natural gas per day (31% of production). In first quarter 2015, sales volumes totaled 18.4 million Boe, or 204,547 Boe per day, which was below production for the quarter.

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

	1Q	4Q	1Q
Boe per day	2015	2014	2014
North Region:			
North Dakota Bakken	120,957	115,137	83,725
Montana Bakken	14,581	15,646	13,732
Red River Units	12,953	13,259	14,140
Other	681	690	824
South Region:			
SCOOP	49,882	40,403	29,363
NW Cana	3,433	3,780	5,685
Arkoma	2,124	2,318	2,565
Other	2,218	2,223	2,437
Total	206,829	193,456	152,471

Bakken

Continental's Bakken production averaged 135,538 Boe per day in the first quarter of 2015, an increase of 4% compared to fourth quarter 2014 and an increase of 39% compared to first quarter 2014. The Company completed 66 net (199 gross) operated and non-operated Middle Bakken and Three Forks wells during first quarter 2015.

During the first quarter, the Company operated an average of 13 rigs in the Bakken, down from 19 rigs at year-end 2014. The Company plans to average 10 operated rigs through the remainder of 2015, based on current market conditions.

Continental significantly reduced its completion crew count in the Bakken during the first quarter of 2015, as planned. The Company has three completion crews active, down from 10 at year-end 2014, and plans to maintain approximately three crews throughout 2015, based on current market conditions. The Company currently has 115 gross operated Bakken wells drilled and waiting on first production, compared to 122 at year-end 2014. The Company expects to have approximately 90 gross operated Bakken wells drilled and waiting on first production at year-end 2015.

Continental's 2015 Bakken drilling program is focused on core leasehold in Williams, McKenzie, Mountrail and Dunn counties to maximize returns. With this concentration on the core of the play, the Company is also entering the first stage of full-field development. Approximately 60% of the wells in the 2015 program will be drilled on 660-foot to 880-foot inter-well spacing in the Middle Bakken and Three Forks reservoirs.

The Company plans to continue completing wells in its 2015 Bakken drilling program with 30-stage enhanced completions to maximize production rates and recoverable reserves per well. In Williams and McKenzie counties, where the Company has its largest data set, enhanced completions are delivering an average 90-day production increase of approximately 40% for hybrid completions and 50% for slickwater completions, compared with offset legacy wells. The Company is projecting estimated ultimate recovery (EUR) uplifts in a range of 25% to 45% for enhanced completions in Williams and McKenzie counties, and, as it expands drilling activity into Mountrail and Dunn counties, it expects to see similar uplifts in production and EURs. The Company's 2015 Bakken drilling program is targeting an average EUR of approximately 800,000 Boe per well.

SCOOP

In first quarter 2015, SCOOP net production averaged 49,882 Boe per day, an increase of 23% sequentially over fourth quarter 2014 and 70% over first quarter 2014. SCOOP production represented 24% of the Company's total production in first quarter 2015.

During first quarter 2015, the Company completed 36 net (74 gross) operated and non-operated wells while operating an average of 20 rigs in SCOOP, targeting the Woodford and Springer formations. Continental plans to maintain approximately 12 operated rigs in SCOOP through year end based on current market conditions. The Company averaged four completion crews in SCOOP since the beginning of the year and plans to maintain three to four in the region throughout 2015.

SCOOP Woodford: Poteet Density Test Delivers Outstanding Results

In first quarter 2015, SCOOP Woodford net production averaged 41,505 Boe per day, an increase of 20% sequentially over fourth quarter 2014. In first quarter 2015, the Company completed 25 net (59 gross) operated and non-operated Woodford wells in the play. The Company plans to average 9 to 11 operated drilling rigs targeting the Woodford through the remainder of the year.

The average initial one-day test rate from operated and non-operated wells completed during the first quarter of 2015 was 1,430 Boe per well. Select initial test rates from recent SCOOP Woodford operated wells include:

- The Singer 2-18-7XH well in Grady County tested at 8.6 MMcfe per day (1,436 Boe), which included 423 Bo per day, from 6,672 feet of completed lateral. The well had a 30-day average rate of 7.5 MMcfe per day (1,250 Boe), and Continental has a 78% working interest in the well; and
- The Thurston 1-35H well in Grady County tested at 5.7 MMcfe per day (955 Boe), which included 348 Bo per day, from 4,569 feet of completed lateral. Continental owns a 93% working interest in the well, which does not yet have 30 days of production history.

An important SCOOP milestone in first quarter 2015 was the completion and initial sales in early March from the 10-well Poteet density pilot project. The Poteet wells flowed at combined peak production rates of 147 MMcf and 3,240 Bo per day. The Company has an average working interest in the wells of 94%.

The cumulative production to date for the 10 Poteet density wells is a total of 6.5 Bcf and 131,800 Bo. The wells are currently averaging combined production rates of 106 MMcf and 1,730 Bo per day, with flowing tubing pressure ranging from 1,500 to 2,400 psi.

The Poteet project was the Company's first dual-level density pilot in the SCOOP Woodford condensate window and consisted of five wells each in the upper and lower halves of the Woodford with approximately 150 feet of vertical separation. Wells in each group were spaced approximately 1,025 feet apart, with an average lateral length of 7,515 feet. The Poteet unit is located in the northeastern corner of Stephens County, where the Woodford formation is approximately 380 feet thick.

"We are very pleased with the early results from the Poteet density pilot. This is a very encouraging indicator of SCOOP's Woodford resource potential," said Jack Stark, President and Chief Operating Officer.

SCOOP Springer Continues to Impress

In first quarter 2015, SCOOP Springer net production averaged 8,377 Boe per day, an increase of 42% sequentially over fourth quarter 2014. The Company completed 11 net (15 gross) operated and non-operated Springer wells in first quarter 2015. The Company plans to average one to three operated drilling rigs targeting the Springer formation through the remainder of the year.

The average initial one-day test rate from operated and non-operated SCOOP Springer wells completed during first quarter 2015 was 1,081 Boe per well. Select test rates from recent operated wells include:

- The Ramsey Trust 1-16-9XH well in Grady County tested at 2,235 Boe per day (81% oil) from 6,615 feet of completed lateral. This is the first extended lateral well completed by Continental in the Springer. The well had a 30-day average rate of 1,731 Boe per day, and Continental has a 73% working interest in the well;
- The Omer 1-17H well in Garvin County tested at 1,354 Boe per day (84% oil) from 4,693 feet of completed lateral. The well had a 30-day average rate of 1,229 Boe per day, and Continental has a 75% working interest in the well; and
- The Jerry 1-15H well in Stephens County tested at 1,052 Boe per day (85% oil) from 4,467 feet of completed lateral. The well had a 30-day average rate of 645 Boe per day, and Continental has a 50% working interest in the well.

Springer completions for the first quarter 2015 also included Continental's second Springer oil window density pilot located in Grady County. The four-well Jeanna density pilot had combined peak production rates of 4.4 MMcf and 3,123 Bo per day, or 963 Boe per well. The Jeanna pilot wells were spaced approximately 1,320 feet apart and averaged 4,644 feet in lateral length.

Northwest Cana JDA

In first quarter 2015, Northwest Cana net production averaged 3,433 Boe per day. During the quarter the Company began drilling under a Joint Development Agreement (JDA) with SK E&S. Continental currently owns approximately 31,000 net acres in the Northwest Cana JDA, targeting the Woodford reservoir. Continental is the operator under the JDA, with SK E&S funding half of Continental's capital requirements until a $270 million carry is exhausted. In late April the Company completed its first well under the agreement, the Schantz 1-5-8XH well in Blaine County (in which Continental owns a 47% working interest). Early results show the well flowing at 14.0 MMcf per day on cleanup, with the rate continuing to improve.

Continental plans to continue drilling with four rigs in NW Cana through year-end 2015.

STACK

The Company also owns approximately 134,000 net acres of leasehold in the emerging STACK play in Blaine, Dewey and Kingfisher counties. The Company is drilling its initial well in the STACK play at this time targeting the Meramec reservoir.

Financial Update and Guidance

In first quarter 2015, Continental's average realized sales price excluding the effects of derivative positions was $38.56 per Bo and $2.70 per Mcf, or $31.65 per Boe. Settlements of matured commodity derivative positions generated a $0.69 gain per Mcf of natural gas, resulting in a net gain on matured derivatives of $23.4 million, or $1.27 per Boe, for the first quarter of 2015. Based on realizations without the effect of derivatives, the Company's first quarter 2015 oil differential was $10.01 per barrel below the NYMEX daily average for the period. The realized natural gas price differential for first quarter 2015 was a negative $0.28 per Mcf.

All operating costs were in line with or better than annual guidance for first quarter 2015. Production expense per Boe was $5.05, a decrease of $0.26 per Boe from fourth quarter 2014. Other select operating costs and expenses for first quarter 2015 included production taxes of 8.2% on oil and natural gas sales; depreciation, depletion and amortization (DD&A) expense of $21.00 per Boe; cash general and administrative (G&A) expense of $1.85 per Boe; and equity compensation expense of $0.61 per Boe.

Non-acquisition capital expenditures for first quarter 2015 totaled approximately $984 million, which was $57 million, or 5%, below budget for the quarter. Total capital expenditures for the quarter included $914 million in exploration and development drilling, $29 million in leasehold and seismic, and $41 million in workovers, recompletions and other. In addition, acquisition capital expenditures totaled approximately $37 million for first quarter 2015.

As of March 31, 2015, Continental's balance sheet included approximately $48 million in cash and cash equivalents, and $6.8 billion in long-term debt, including $955 million of borrowings against the Company's credit facility. In February 2015, the Company increased the commitments under its existing credit facility to $2.5 billion, providing incremental liquidity.

"As we discussed on our February earnings call, Continental is moving toward balancing cash flow and capital expenditures by mid-year," said John Hart, Chief Financial Officer. "We did an excellent job managing both operating costs and capital expenditures with a disciplined approach during the first quarter. We have ample liquidity with our expanded revolver to support operations through the remainder of the year. Our expectation is for cash flow to improve as world crude oil supply and demand rebalance later this year, which should be accompanied by strengthening oil prices."

Continental's 2015 guidance remains unchanged as disclosed on February 24, 2015. Due to its strong operating performance and the industry's commodity price volatility, the Company may review its 2015 guidance with the announcement of its second quarter results in early August 2015. A table with the Company's full 2015 guidance, which includes differentials and select cost elements, can be found at the conclusion of this 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.

	1Q 2015	4Q 2014	1Q 2014
Average daily production:			
Crude oil (Bbl per day)	143,511	136,972	106,398
Natural gas (Mcf per day)	379,906	338,907	276,439
Crude oil equivalents (Boe per day)	206,829	193,456	152,471
Average sales prices, excluding effect from derivatives:			
Crude oil ($/Bbl)	$38.56	$61.53	$89.73
Natural gas ($/Mcf)	$2.70	$4.36	$7.06
Crude oil equivalents ($/Boe)	$31.65	$51.11	$75.03
Production expenses ($/Boe)	$5.05	$5.31	$5.76
Production taxes (% of oil and gas revenues)	8.2%	8.3%	7.7%
DD&A ($/Boe)	$21.00	$22.39	$20.43
General and administrative expenses ($/Boe)	$1.85	$2.00	$2.43
Non-cash equity compensation ($/Boe)	$0.61	$0.85	$0.83
Net income (loss) (in thousands)	($131,971)	$114,048	$226,234
Diluted net income (loss) per share (1)	($0.36)	$0.31	$0.61
Adjusted net income (loss) (in thousands) (2)	($33,819)	$420,770	$272,297
Adjusted diluted net income (loss) per share (1)(2)	($0.09)	$1.14	$0.74
EBITDAX (in thousands) (2)	$439,427	$1,185,071	$775,407

(1) Net income per share amounts for the 1Q 2014 period have been retroactively adjusted to reflect the Company's 2-for-1 stock split in September 2014.

(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 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.

First Quarter Conference Call

Continental plans to host a conference call to discuss first quarter results on Thursday, May 7, 2015, 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, May 7, 2015
Dial-in:	888-895-5271
Intl. dial-in:	847-619-6547
Pass code:	39335428

A replay of the call will be available for 30 days on the Company's website or by dialing:

Replay number:	888-843-7419
Intl. replay	630-652-3042
Pass code:	39335428

Continental plans to publish a first quarter 2015 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on May 7, 2015.

Upcoming Conferences

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

May 13, 2015	Morgan Stanley E&P and Oil Services Conference: Houston
June 1-2, 2015	RBC Capital Markets' Global Energy and Power Executive Conference: NYC
June 18, 2015	JP Morgan Sixth Annual Oil & Gas 1x1 Forum: Boston

Instructions regarding how to access the live and replay webcast for the RBC Capital Markets' presentation and presentation materials for all conferences mentioned 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 lower 48 United States 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 Northwest Cana play. With a focus on the exploration and production of oil, Continental has unlocked the technology and resources vital to American energy independence and is a strong free market advocate in favor of lifting the domestic crude oil export ban. In 2015, the Company will celebrate 48 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, returns, budgets, costs, business strategy, objectives, and cash flow, 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, registration statements and other reports filed from time to time with the SEC, and other announcements the Company makes from time to time.

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

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

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

Investor Contact:	Media Contact:
J. Warren Henry	Kristin Thomas
Vice President, Investor Relations & Research	Vice President, Public Relations
405-234-9127	405-234-9480
Warren.Henry@CLR.com	Kristin.Thomas@CLR.com
Alyson L. Gilbert	
Senior Analyst, Investor Relations	
405-774-5814	
Alyson.Gilbert@CLR.com	

Continental Resources Inc.

Unaudited Condensed Consolidated Statements of Income (Loss)

	Three months ended March 31,	
	2015	2014
Revenues:	In thousands, except per share data	
Crude oil and natural gas sales	$ 582,592	$ 1,002,333
Gain (loss) on derivative instruments, net	32,755	(39,674)
Crude oil and natural gas service operations	10,297	9,836
Total revenues	625,644	972,495
Operating costs and expenses:		
Production expenses	92,941	76,886
Production taxes and other expenses	48,362	78,302
Exploration expenses	14,340	4,813
Crude oil and natural gas service operations	3,894	8,074
Depreciation, depletion, amortization and accretion	386,512	272,861
Property impairments	147,561	58,208
General and administrative expenses	45,380	43,536
(Gain) loss on sale of assets, net	(2,070)	8,498
Total operating costs and expenses	736,920	551,178
Income (loss) from operations	(111,276)	421,317
Other income (expense):		
Interest expense	(75,063)	(62,975)
Other	347	759
	(74,716)	(62,216)
Income (loss) before income taxes	(185,992)	359,101
Provision (benefit) for income taxes	(54,021)	132,867
Net income (loss)	$ (131,971)	$ 226,234
Basic net income (loss) per share(1)	$ (0.36)	$ 0.61
Diluted net income (loss) per share(1)	$ (0.36)	$ 0.61

(1) Net income per share amounts for the 1Q 2014 period have been retroactively adjusted to reflect the Company's 2-for-1 stock split in September 2014.

Continental Resources Inc.

Unaudited Condensed Consolidated Balance Sheets

	March 31, 2015	December 31, 2014
Assets	In thousands	
Current assets	$ 1,200,880	$ 1,389,601
Net property and equipment [(1)]	14,111,154	13,635,852
Other noncurrent assets	123,230	119,617
Total assets	$ 15,435,264	$ 15,145,070
Liabilities and shareholders' equity		
Current liabilities	$ 1,600,939	$ 1,952,013
Long-term debt	6,784,816	5,995,837
Other noncurrent liabilities	2,208,471	2,229,376
Total shareholders' equity	4,841,038	4,967,844
Total liabilities and shareholders' equity	$ 15,435,264	$ 15,145,070

(1) Balance is net of accumulated depreciation, depletion and amortization of $5.11 billion and $4.65 billion as of March 31, 2015 and December 31, 2014, respectively.

Continental Resources Inc.

Unaudited Condensed Consolidated Statements of Cash Flows

	Three months ended March 31,	
In thousands	2015	2014
Net income (loss)	$ (131,971)	$ 226,234
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Non-cash expenses	495,096	498,339
Changes in assets and liabilities	159,065	(33,911)
Net cash provided by operating activities	522,190	690,662
Net cash used in investing activities	(1,278,404)	(1,019,480)
Net cash provided by financing activities	784,383	351,871
Effect of exchange rate changes on cash	(4,905)	-
Net change in cash and cash equivalents	23,264	23,053
Cash and cash equivalents at beginning of period	24,381	28,482
Cash and cash equivalents at end of period	$ 47,645	$ 51,535

Non-GAAP Financial Measures

EBITDAX

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. EBITDAX represents 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 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 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 to EBITDAX for the periods presented.

In thousands	1Q 2015	4Q 2014	1Q 2014
Net income (loss)	$ (131,971)	$ 114,048	$ 226,234
Interest expense	75,063	74,200	62,975
Provision (benefit) for income taxes	(54,021)	77,682	132,867
Depreciation, depletion, amortization and accretion	386,512	395,260	272,861
Property impairments	147,561	393,803	58,208
Exploration expenses	14,340	20,535	4,813
Impact from derivative instruments:			
Total (gain) loss on derivatives, net	(32,755)	(387,958)	39,674
Total cash received (paid) on derivatives, net	23,435	482,567	(33,264)
Non-cash (gain) loss on derivatives, net	(9,320)	94,609	6,410
Non-cash equity compensation	11,263	14,934	11,039
EBITDAX	$ 439,427	$ 1,185,071	$ 775,407

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

In thousands

	1Q 2015	4Q 2014	1Q 2014
Net cash provided by operating activities	$ 522,190	$ 1,077,864	$ 690,662
Current income tax provision (benefit)	5	(2,258)	1,552
Interest expense	75,063	74,200	62,975
Exploration expenses, excluding dry hole costs	5,939	5,998	4,813
Gain (loss) on sale of assets, net	2,070	1,552	(8,498)
Other, net	(6,775)	(4,429)	(10,008)
Changes in assets and liabilities	(159,065)	32,144	33,911
EBITDAX	$ 439,427	$ 1,185,071	$ 775,407

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 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. Net income per share amounts for the 1Q 2014 period have been retroactively adjusted to reflect the Company's 2-for-1 stock split in September 2014.

	1Q 2015		4Q 2014		1Q 2014	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS	After-Tax $	Diluted
Net income (loss) (GAAP)	$ (131,971)	$(0.36)	$ 114,048	$ 0.31	$ 226,234	$ 0.61
Adjustments, net of tax:						
Non-cash (gain) loss on derivatives, net	(5,778)	(0.01)	59,603	0.16	4,038	0.01
Property impairments	105,214	0.28	248,096	0.67	36,671	0.10
(Gain) loss on sale of assets, net	(1,284)	-	(977)	-	5,354	0.02
Adjusted net income (loss) (Non-GAAP)(1)	$ (33,819)	$(0.09)	$ 420,770	$ 1.14	$ 272,297	$ 0.74
Weighted average diluted shares outstanding	369,385		370,545		370,056	
Adjusted diluted net income (loss) per share (Non-GAAP) (1)	$ (0.09)		$ 1.14		$ 0.74	

(1) Balance for the 4Q 2014 period includes $348 million of pre-tax gains ($219 million after tax, or $0.59 per diluted share) recognized from crude oil derivative contracts that were monetized in the 2014 fourth quarter prior to their contractual maturities scheduled for 2015 and 2016.

Continental Resources Inc.

2015 Guidance

	2015
Production growth (YOY)	16% to 20%
Capital expenditures (non-acquisition, in $ billions)	$2.7
Operating Expenses:	
Production expense per Boe	$5.50 to $6.00
Production tax (% of oil & gas revenue)	7.5% to 8.5%
G&A expense per Boe	$2.00 to $2.50
Non-cash equity compensation per Boe	$0.75 to $0.95
DD&A per Boe	$20.00 to $22.50
Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	($7.00) to ($10.00)
Henry Hub natural gas (per Mcf)	$0.00 to ($0.50)
Income tax rate	38%
Deferred taxes	90% to 95%