CLR Investors

Continental Resources Reports Second Quarter 2013 Results

Record Production Totaling 135,700 Boe per Day for Second Quarter 2013, an Increase of 12% Sequentially and 43% Compared to Second Quarter 2012
Adjusted Net Income for Second Quarter 2013 of $246 Million, or $1.33 per Diluted Share; Record EBITDAX of $708 Million, an Increase of 14% Compared to First Quarter 2013 and 68% Compared to Second Quarter 2012
Mid-Year 2013 Proved Reserves Total 922 Million Boe, an Increase of 17% from Year-End 2012
Lower Three Forks Activity Delineates Productive Footprint of 3,800 Square Miles in Bakken
2013 Production Growth Target Range Tightened Upward to 38% to 40%; Bakken Operated Well Cost Target Lowered to $8.0 Million by Year-End 2013

OKLAHOMA CITY, Aug. 7, 2013 /PRNewswire/ -- Continental Resources, Inc. (NYSE: CLR) ("Continental" or the "Company") announced second quarter 2013 operating and financial results, reporting net income of $323 million, or $1.75 per diluted share. Adjusted net income, which excludes items typically excluded from published analyst estimates, totaled $246 million, or $1.33 per diluted share. The Company achieved record EBITDAX of $708 million, an increase of $87 million or 14% compared to first quarter 2013. Definitions and reconciliations of adjusted net income, adjusted earnings per share and EBITDAX to the most directly comparable U.S. GAAP financial measures can be found in the supporting tables at the conclusion of this release.

(Logo: http://photos.prnewswire.com/prnh/20120327/DA76602LOGO)

Significant second quarter 2013 operational highlights include:

- Record net production of approximately 135,700 barrels of oil equivalent ("Boe") per day in second quarter 2013, of which 71% is crude oil;
- Net Bakken production increased to approximately 88,000 Boe per day for second quarter 2013, representing 65% of total production;
- Recent lower Three Forks completions further delineate the productive footprint across 3,800 square miles in the Bakken; and
- Net production from South Central Oklahoma Oil Province ("SCOOP") play increased to approximately 17,550 Boe per day, up 23% from first quarter 2013.

"Continental continues to deliver exceptional oil growth while maintaining capital discipline," said Harold G. Hamm, Continental's Chairman and Chief Executive Officer. "We are extremely pleased with our progress to date on productivity and interference testing in the lower Three Forks benches across a large area. Our industry-leading approach to scientifically understanding the field will allow us to optimize the development of America's greatest oil play – the Bakken. At the same time, our SCOOP play is having tremendous success in growth and delineation."

Production, Realizations and Expenses

Second quarter 2013 net production totaled 12.3 million Boe, or approximately 135,700 Boe per day, a sequential increase of 12% from first quarter 2013. Total net production included approximately 96,000 barrels of oil per day (71% of production) and approximately 238 million cubic feet of natural gas per day (29% of production). The Company currently sells its natural gas prior to processing based upon pricing provisions in its natural gas contracts. The Company estimates that if it had sold its natural gas liquids after processing, the combined natural gas liquids and oil would account for more than 80% of total production. Current production is estimated at approximately 140,000 Boe per day.

Continental's average realized sales price excluding the effects of derivative positions was $87.22 per barrel of oil and $5.22 per thousand cubic feet ("Mcf") of natural gas, or $71.13 per Boe for second quarter 2013. Realized settlements of commodity derivative positions generated a $0.26 gain per barrel of oil and $0.33 loss per Mcf of natural gas resulting in a net realized hedging loss of $4.8 million, or $0.38 per Boe for the second quarter 2013. Based on realizations without the effect of derivatives, the Company's second quarter 2013 oil differential was $7.07 per barrel below the NYMEX WTI daily average for the period. The realized natural gas price differential for second quarter 2013 was a positive $1.13 to Henry Hub.

Production expense per Boe was $5.86 for second quarter 2013, above the Company's expectations due to adverse weather conditions, which temporarily impacted production costs in certain areas. Other select operating costs and expenses for second quarter 2013 included production taxes of 8.3% of oil and natural gas sales; DD&A of $18.88 per Boe and G&A (cash and non-cash, excluding relocation expenses) of $2.81 per Boe, all within or better than the range of the Company's annual guidance. The Company's 2013 guidance can be found on the last page of this release.

W. F. "Rick" Bott, Continental's President and Chief Operating Officer, added, "Given our solid execution and performance in the first half of the year, we are tightening our annual production growth guidance range upward from 35% to 40%, to 38% to 40%, while maintaining our original $3.6 billion non-acquisition capital expenditure budget. Our focus and capital discipline, as well as continued strong commodity prices, have put us in a position for a strong finish to 2013, which underscores our confidence in achieving our 5-year growth targets."

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

Boe per day	2Q 2013	1Q 2013	2Q 2012
North Region:			
North Dakota Bakken	76,909	67,575	47,166
Montana Bakken	11,081	9,352	6,305
Red River Units	14,886	15,055	15,482
Other	2,141	1,267	1,445
South Region:			
SCOOP	17,547	14,243	3,282
NW Cana	7,763	8,323	13,390
Arkoma	3,064	3,234	3,806
Other	2,309	2,483	2,912
East Region	-	-	1,064
Total	135,700	121,532	94,852

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.

	2Q 2013	1Q 2013	2Q 2012
Average daily production:			
Crude oil (Bbl per day)	96,029	86,071	65,274
Natural gas (Mcf per day)	238,028	212,766	177,471
Crude oil equivalents (Boe per day)	135,700	121,532	94,852

Average sales prices, excluding effect from derivatives:			
Crude oil ($/Bbl)	$87.22	$89.99	$80.56
Natural gas ($/Mcf)	$5.22	$4.99	$3.51
Crude oil equivalents ($/Boe)	$71.13	$72.31	$61.69
Production expenses ($/Boe)	$5.86	$5.70	$5.16
Production taxes (% of oil and gas revenues)	8.3%	8.2%	8.1%
DD&A ($/Boe)	$18.88	$19.72	$18.98
General and administrative expenses ($/Boe) (1)	$2.03	$2.20	$2.20
Non-cash equity compensation ($/Boe)	$0.78	$0.85	$0.92
Net income (in thousands)	$323,270	$140,627	$405,684
Diluted net income per share	$1.75	$0.76	$2.25
Adjusted net income (in thousands) (2)	$245,728	$215,386	$122,816
Adjusted diluted net income per share (2)	$1.33	$1.17	$0.68
EBITDAX (in thousands) (2)	$708,107	$621,528	$421,860

(1) General and administrative expenses ($/Boe) exclude non-recurring corporate relocation expenses of $0.7 million ($0.05 per Boe) for second quarter 2013, $0.7 million ($0.06 per Boe) for first quarter 2013, and $3.3 million ($0.39 per Boe) for second quarter 2012.

(2) Adjusted net income, adjusted diluted net income 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, diluted net income 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, adjusted diluted net income per share, and EBITDAX to the most directly comparable U.S. GAAP financial measures are provided subsequently under the header *Non-GAAP Financial Measures*.

Mid-Year 2013 Proved Reserves Update

Proved reserves increased to 922 million Boe as of June 30, 2013, based on internal estimates, an increase of 17% from year-end 2012. The Company's proved reserve PV10 value increased by approximately $3 billion to $16.2 billion. Continental operates 87% of its proved reserves, and 70% are crude oil.

Strong Bakken Production Growth

Net production from the Company's industry-leading activity in the Bakken play in North Dakota and Montana increased to approximately 88,000 Boe per day in second quarter 2013, an increase of 14% sequentially and 65% above second quarter 2012. The Company's gross operated Bakken production averaged 112,000 Boe per day in second quarter 2013. Continental operated 20 rigs across its leasehold position of approximately 1.2 million net acres in the Bakken play. The Company is able to operate fewer rigs while achieving the upper end of its production guidance due to the realization of meaningful drilling efficiency gains.

The Company participated in completing 73 net (180 gross) wells in second quarter 2013. The Company's Bakken backlog of gross operated wells drilled, but not yet completed, is currently 75 wells.

Development drilling and completion activity for second quarter 2013 continued to meet expectations. In North Dakota, Company-operated wells completed during second quarter 2013 averaged an initial one-day test of 1,150 Boe per day, which included 84% oil. Company-operated Montana wells completed during second quarter 2013 averaged an initial one-day test of 455 Boe per day, which included 94% oil. These results are consistent with the Company's estimated ultimate recovery ("EUR") models of 603,000 Boe for North Dakota wells and 430,000 Boe for Montana wells.

The Company has experienced continual success driving operated drilling and completion costs lower in the Bakken. These savings have a direct impact on overall returns on development and exploratory efforts. For example, comparing second quarter 2013 with second quarter 2012, Continental's drilling cycle time of well spud to total depth has improved by approximately 20%, a reduction of 4 days; time spent drilling the lateral section of the well has improved by nearly 30%, a reduction of more than 2.5 days; and time and cost of rig moves is down substantially as the Company's activity on multiple well drilling pads has increased. Currently, 70% of the Company's drilling rig activity in the Bakken is on multiple well pads.

Richard E. Muncrief, Continental's Senior Vice President of Operations, stated, "We are very proud of our industry-leading efficiency performance in the Bakken. Our consistent goal is to be the premier operator in the play. Our combination of focus, strong working relationships with service providers, commitment to safety and continual process improvements have driven these results. Our initial target was to lower our operated well cost by $1 million per well by year-end 2013 to $8.2 million and now we think we can get to $8.0 million or lower per operated well."

Lower Three Forks Activity

Continental's 2013 Lower Three Forks (LTF) exploration program is on target to complete 20 new wells by year-end to establish productive capacity in all LTF intervals, identify unique reserves and de-risk a broad area where the company has existing leasehold. To date, the Company has completed 14 LTF wells, which include one Three Forks first bench (TF1) interference test well, six Three Forks second bench (TF2) wells, five Three Forks third bench (TF3) wells and two Three Forks fourth bench (TF4) wells. The TF2 and TF3 wells have average 24-hour initial production rates of 1,200 Boe per day and 970 Boe per day, respectively. The outline of these LTF producers defines a productive area of approximately 3,800 square miles.

The following table summarizes the Company's LTF activity and indicates there are eight more LTF wells planned by year-end 2013.

Lower Three Forks Exploration Well Status

Zone	**Drilling**	**Completing**	**Producing**	**To Be Drilled**	**Total**
TF1		2	1	1	4
TF2	1	2	6	2	11
TF3			5		5
TF4			2		2
Total	**1**	**4**	**14**	**3**	**22**

Data in table includes two wells drilled in late 2011 and 2012 and 20 wells drilled or planned in 2013

At this time, 85% of the LTF wells have less than 120 days of production, and most have less than 90 days of production. The Company is monitoring early production from the wells closely, and the data indicates the wells are producing in line with typical TF1 producers in each area of the play. Continental's longest producing LTF wells, the Charlotte 2-22H and 3-22H, have produced a cumulative 123,000 Boe and 68,000 Boe, respectively, since initial production began in late 2011 and late 2012. To date, Continental has not seen evidence of production interference in its LTF exploration program, except in the Colter spacing unit in Dunn County.

In the Colter unit, the Company observed direct evidence of production interference between a Middle Bakken (MB) well, TF1 legacy well and two newly completed LTF bench wells. The Company interprets natural vertical fracturing has connected the MB and LTF reservoirs in this 1,280-acre spacing unit. This area of the Nesson Anticline exhibits more pronounced faulting and natural vertical fracturing associated with uplift. Continental observed some pressure draw-down in its two new TF2 and TF4 completions, the Colter 3-14H-2 and 4-4H-4, and believes the reduced pressure relates to existing TF1 and MB wells producing above them in the unit. These two legacy wells, located on the east side of the Colter unit, commenced production in 2008 and 2011, respectively, and have produced a cumulative 530,000 Boe. All four wells are vertically aligned within a 660'-wide window. On the west side of the Colter unit, Continental recently completed a fifth well, the Colter 5-14H-3. This TF3 producer is flowing 1,750 Boe per day at 3,200 psi with no indication of pressure draw-down.

Other LTF recent completions in second quarter 2013 include a TF2 producer, the Charlotte 6-22H well, which had an initial test of 730 Boe per day; TF3 producers include the Barney 3-29H-3, which had an initial test of 1,190 Boe per day, and the Rosenvold 3-30H-3, which had an initial test of 520 Boe per day. Continental completed the industry's first TF4 well in the Bakken, the Farver 2-29H-4 well in Divide County, which was recently completed flowing 480 Boe per day.

Bakken Downspacing Activity

The Company's other Bakken exploration and appraisal initiative involves four pilot density projects to test 320-acre and 160-acre spacing in the MB and first three benches of the TF. The Company plans to complete 47 gross wells in the pilot density program to help determine the optimum spacing and pattern to maximize the ultimate recovery from the multiple Bakken and TF reservoirs.

Continental has drilled all of its planned 11 wells and completion activities are under way on its first 320-acre pilot density project at the Hawkinson pad in Dunn County. The Hawkinson project includes microseismic monitoring of completions from multiple wellbores to help determine the most efficient completion methods to maximize recoveries. This is likely to be the largest microseismic program utilized to date worldwide. Drilling is under way on the 13-well, 160-acre pilot on the Wahpeton pad in McKenzie County and the 12-well, 320-acre pilot on the Tangsrud pad in Divide County. One additional 320-acre pilot project at the 11-well Rollefstad pad has spud its initial well. In summary, of the 47-well pilot density program across four pads, 23 wells have been drilled and are waiting on completion. Once each pad has reached initial production, the wells will be announced together as part of the Company's quarterly results.

The Company plans to complete 245 net (790 gross) wells in the Bakken in 2013, including both operated and non-operated wells. The Company estimates its operated rig activity will average 20 rigs throughout the balance of the year, which should deliver the planned production growth and stay within capital expenditure guidance.

SCOOP Success Continues

Continental continues to experience excellent repeatable results from its drilling activity in the SCOOP. The play, discovered by Continental and disclosed in October 2012, currently extends approximately 80 miles across Grady, Stephens, McClain and Carter counties in Oklahoma and contains an oil and condensate-rich window. To date, more than 90 gross wells in the area have de-risked the productive footprint for more than 40 miles. Continental is the largest producer, most active operator and largest leaseholder with approximately 277,000 net acres in the play. In second quarter 2013, SCOOP net production averaged approximately 17,550 Boe per day, an increase of 23% sequentially and 435% above second quarter 2012. The recent growth was driven by the addition of eight net (14 gross) operated and non-operated wells in the play during the second quarter 2013.

In the condensate window, initial one-day tests averaged approximately 1,490 Boe per day, which included 29% oil for wells completed during second quarter 2013. Completed second quarter 2013 wells in the oil window averaged approximately 1,460 Boe per day, which included 55% oil. Continental completed its first cross-unit extended lateral at the Singer 1-18-7XH well in Grady County to enhance productivity from one surface location. The well was drilled to a total measured depth of 25,105 feet, with the lateral portion 9,377 feet. This extended lateral is an additional 4,877 feet longer than the standard 4,500 feet of lateral with traditional 640-acre spacing. Initial expectations for cross-unit wells could double production and proved reserves with only an incremental increase of 55% to 60% in cost.

Select Continental-operated SCOOP wells completed in second quarter 2013 include:

- The Vanarkel 1-15H well in Stephens County produced 2,045 Boe per day (44% oil) in its initial one-day test period;
- The Singer 1-18-7XH well in Grady County produced 1,915 Boe per day (37% oil) in its initial one-day test period; and
- The Dicksion 1-21H well in Grady County produced 1,590 Boe per day (45% oil) in its initial one-day test period.

The Company is currently operating 10 rigs in the play with plans to increase to 12 by the end of third quarter 2013. The Company plans to complete a total of 55 net (115 gross) wells in the SCOOP play in 2013, including both operated and non-operated wells. These wells will focus on expanding the proved productive extent of the play and de-risking the Company's leasehold.

Financial Update

As of June 30, 2013, Continental's balance sheet included approximately $220 million in cash and cash equivalents and an undrawn $1.5 billion revolving credit facility. During second quarter 2013, the borrowing base was increased to $4.25 billion, with commitments remaining unchanged at $1.5 billion.

Non-acquisition capital expenditures for second quarter 2013 totaled $897 million, including $793 million in exploration and development drilling, $78 million in leasehold and seismic and $26 million in workovers, recompletions and other. Acquisition capital expenditures totaled approximately $101 million for second quarter 2013, and are excluded from the Company's capital expenditure guidance for 2013 of $3.6 billion.

Conference Call Information and Summary Presentation

Continental Resources plans to host a conference call to discuss second quarter 2013 results on Thursday, August 8, 2013 at 11 a.m. ET (10 a.m. CT) and publish a second quarter 2013 summary presentation to its website prior to the start of the conference call in order to be used as reference material. 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:	11 a.m. ET, Thursday, August 8, 2013
Dial in:	888 713 4213
Intl. dial in:	617 213 4865
Pass code:	48272235

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

Replay number:	888 286 8010
Intl. replay	617 801 6888
Pass code:	80677475

Callers who wish to pre-register for the call may go to:

https://www.theconferencingservice.com/prereg/key.process?key=PC998GEJH

Upcoming Company Presentations

Continental management is currently scheduled to present at the following investment conferences. Presentation materials will be available on the Company's website, www.CLR.com, the day of the event.

August 13	EnerCom, Denver
August 27	Morgan Stanley Summer Energy Summit, Houston
September 12	Barclay's CEO Conference, New York City
September 24	Deutsche Bank Energy Conference, Boston

The Company's presentations at the conferences on August 13 and September 12 will be available via webcast. Instructions regarding how to access such webcasts will be available on the Company's web site at www.CLR.com on or prior to the day of the presentations. Such webcasts will be available for 30 days on the Company's web site.

About Continental Resources

Continental Resources (NYSE: CLR) is a Top 10 independent oil producer in the United States. Based in Oklahoma City, Continental is the largest leaseholder and producer in the nation's premier oil field, the Bakken play of North Dakota and Montana. The company also has significant positions in Oklahoma, including its recently discovered SCOOP play and the Northwest Cana play. With a focus on the exploration and production of oil, Continental is on a mission to unlock the technology and resources vital to American energy independence. In 2013, the company will celebrate 46 years of operation. 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, 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 the expectations reflected in the forward-looking statements are reasonable and based on reasonable assumptions, no assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. When considering forward-looking statements, readers should keep in mind the risk factors and other cautionary statements described under Part I, Item 1A. Risk Factors included in the Company's Annual Report on Form 10-K for the year ended December 31, 2012, registration statements and other reports filed from time to time with the Securities and Exchange Commission ("SEC"), and other announcements the Company makes from time to time.

The Company cautions readers these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control, incident to the exploration for, and development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under Part I, Item 1A. Risk Factors in the Company's Annual Report on Form 10-K for the year ended December 31, 2012, 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 hereof. 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. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that the Company, or persons acting on its behalf, may make.

Except as otherwise required by applicable law, the Company disclaims any duty to update any forward-looking statements to reflect events or circumstances after the date of this press release.

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Continental Resources, Inc.
Unaudited Condensed Consolidated Statements of Income

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
Revenues:	*In thousands, except per share data*			
Crude oil and natural gas sales	$ 892,187	$523,393	$1,675,704	$1,075,651
Gain on derivative instruments, net	199,056	471,728	114,225	302,671
Crude oil and natural gas service operations	9,509	9,598	21,052	21,497
Total revenues	1,100,752	1,004,719	1,810,981	1,399,819
Operating costs and expenses:				
Production expenses	73,452	43,756	135,255	83,831
Production taxes and other expenses	82,236	49,227	154,665	99,967
Exploration expenses	11,151	8,702	20,965	12,853
Crude oil and natural gas service operations	7,317	7,255	15,914	17,097
Depreciation, depletion, amortization and accretion	236,790	161,018	450,468	310,473
Property impairments	79,712	35,871	119,793	65,778
General and administrative expenses	35,873	29,813	69,690	54,779
(Gain) loss on sale of assets, net	349	(17,397)	213	(67,024)
Total operating costs and expenses	526,880	318,245	966,963	577,754
Income from operations	573,872	686,474	844,018	822,065
Other income (expense):				
Interest expense	(61,378)	(31,691)	(108,853)	(55,969)
Other	634	789	1,180	1,570
	(60,744)	(30,902)	(107,673)	(54,399)
Income before income taxes	513,128	655,572	736,345	767,666
Provision for income taxes	189,858	249,888	272,448	292,888
Net income	$ 323,270	$405,684	$463,897	$474,778
Basic net income per share	$ 1.76	$2.26	$2.52	$2.64
Diluted net income per share	$ 1.75	$2.25	$2.51	$2.63

Continental Resources, Inc.
Unaudited Condensed Consolidated Balance Sheets

	June 30, 2013	December 31, 2012
Assets	*In thousands*	
Current assets	$1,293,630	$946,783
Net property and equipment	9,440,216	8,105,269
Other noncurrent assets	166,136	87,957
Total assets	$10,899,982	$9,140,009
Liabilities and shareholders' equity		
Current liabilities	$1,257,426	$1,125,865
Long-term debt	4,440,820	3,537,771
Other noncurrent liabilities	1,558,396	1,312,674
Total shareholders' equity	3,643,340	3,163,699

Total liabilities and shareholders' equity$10,899,982$9,140,009

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

	Six months ended June 30,	
	2013	2012
	In thousands	
Net income	$463,897	$474,778
Adjustments to reconcile net income to net cash provided by operating activities:		
Non-cash expenses	739,003	269,885
Changes in assets and liabilities	(45,955)	26,167
Net cash provided by operating activities	1,156,945	770,830
Net cash used in investing activities	(1,850,177)	(1,773,492)
Net cash provided by financing activities	877,916	978,255
Net change in cash and cash equivalents	184,684	(24,407)
Cash and cash equivalents at beginning of period	35,729	53,544
Cash and cash equivalents at end of period	$220,413	$29,137

Non-GAAP Financial Measures

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, and non-cash equity compensation expense. 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. 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.

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. Our credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 4.0 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and the letters of credit under our credit facility plus our note payable and Senior Note obligations, divided by total EBITDAX for the most recent four quarters. Our credit facility defines EBITDAX consistent with the presentation below. The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

	2Q 2013	1Q 2013	2Q 2012
	in thousands		
Net income	$323,270	$140,627	$405,684
Interest expense	61,378	47,475	31,691
Provision for income taxes	189,858	82,590	249,888
Depreciation, depletion, amortization and accretion	236,790	213,678	161,018
Property impairments	79,712	40,081	35,871

Exploration expenses	11,151	9,814	8,702
Impact from derivative instruments:			
Total (gain) loss on derivatives, net	(199,056)	84,831	(471,728)
Total realized loss (cash flow) on derivatives, net	(4,752)	(6,810)	(7,056)
Non-cash (gain) loss on derivatives, net	(203,808)	78,021	(478,784)
Non-cash equity compensation	9,756	9,242	7,790
EBITDAX	$708,107	$621,528	$421,860

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

	Six months ended June 30,	
	2013	2012
	in thousands	
Net cash provided by operating activities	$1,156,945	$770,830
Current income tax provision	5,830	2,150
Interest expense	108,853	55,969
Exploration expenses, excluding dry hole costs	12,902	12,755
Gain (loss) on sale of assets, net	(213)	67,024
Other, net	(637)	(6,169)
Changes in assets and liabilities	45,955	(26,167)
EBITDAX	$1,329,635	$876,392

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 corporate relocation expenses. 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 nonrecurring transactions. 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.

	2Q 2013		1Q 2013		2Q 2012	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (GAAP)	$ 323,270	$ 1.75	$ 140,627	$ 0.76	$ 405,684	$ 2.25
Adjustments, net of tax:						
Non-cash (gain) loss on derivatives, net	(128,399)	$ (0.69)	49,153	0.27	(296,367)	(1.64)
Property impairments	50,219	$ 0.27	25,251	0.14	22,204	0.12
(Gain) loss on sale of assets, net	220	-	(86)	-	(10,769)	(0.06)
Corporate relocation expenses	418	-	441	-	2,064	0.01
Adjusted net income (Non-GAAP)	$ 245,728	$ 1.33	$ 215,386	$ 1.17	$ 122,816	$ 0.68
Weighted average diluted shares outstanding	184,739		184,656		180,335	
Adjusted diluted net income per share (Non-GAAP)	$ 1.33		$ 1.17		$ 0.68	

Continental Resources, Inc.
2013 Guidance Outlook
As of August 7, 2013(1)

Production growth	**38% to 40%**
Capital expenditures [(2)]	$3.6 billion
Price differentials:	
NYMEX WTI crude oil (per barrel of oil)	($5.00) to ($7.00)
Henry Hub natural gas (per Mcf)	+$1.00 to +$1.50
Operating expenses:	
Production expense per Boe	$5.20 to $5.60
Production tax (% of oil and gas revenues)	8% to 9%
DD&A per Boe	$19.00 to $21.00
G&A expense per Boe	$2.20 to $2.70
Non-cash equity compensation per Boe	$0.70 to $0.90
Income tax rate	37%
Deferred taxes	90% to 95%

(1) Changes to previous Outlook dated May 8, 2013 are presented in bold.
(2) Excludes acquisition capital expenditures.

SOURCE Continental Resources

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http://investors.clr.com/2013-08-07-Continental-Resources-Reports-Second-Quarter-2013-Results