UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported): February 27, 2013 (February 26, 2013)

RANGE RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**001-12209**	**34-1312571**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

100 Throckmorton, Suite 1200 **Ft. Worth, Texas**	**76102**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (817) 870-2601

(Former name or former address, if changed since last report): Not applicable

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

ITEM 2.02 Results of Operations and Financial Condition

On February 26, 2013 Range Resources Corporation issued a press release announcing its 2012 results. A copy of this press release is being furnished as an exhibit to this report on Form 8-K.

ITEM 9.01 Financial Statements and Exhibits

(d) Exhibits:

99.1 Press Release dated February 26, 2013

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

RANGE RESOURCES CORPORATION

By: /s/ *Roger S. Manny*
Roger S. Manny
Chief Financial Officer

Date: February 27, 2013

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press Release dated February 26, 2013

RANGE REPORTS OUTSTANDING 2012 RESULTS

FORT WORTH, TEXAS, FEBRUARY 26, 2013…RANGE RESOURCES CORPORATION (NYSE: RRC) today announced its 2012 financial results.

2012 Highlights –

- Reports record annual production of 753 Mmcfe per day, an increase of 36% over 2011, with fourth quarter oil and NGL volumes increasing 41%
- Reports 29% increase in total proved reserves to 6.5 Tcfe, with oil and NGL reserves increasing 64%
- Drill bit reserve replacement of 773% at $0.86 per mcfe all-in finding and development cost
- Fourth quarter adjusted non-GAAP cash flow of $1.54 per share exceeds average First Call consensus estimates by 18 cents
- Fourth quarter adjusted non-GAAP earnings of $0.46 per share exceeds average First Call consensus estimates by 17 cents
- Unit costs continue to decline, highlighted by 32% reduction in lease operating costs compared to 2011
- Innovative marketing arrangements increased price realizations from propane exports
- Unrisked resource potential increases to 48—68 Tcfe, including 2.3 – 3.5 billion barrels of oil and NGLs
- Asset sale agreement recently executed for $275 million

As previously reported, production for 2012 averaged 753 Mmcfe per day, a 36% increase over 2011. Fourth quarter 2012 production volumes averaged 844 Mmcfe per day, another record high for Range. Fourth quarter 2012 production increased 35% over the prior-year period and was 7% higher than third quarter 2012. Oil and NGL production increased 41% during the fourth quarter reflecting the Company’s focus on its high return, liquids-rich plays during 2012.

Proved reserves increased 29% year-over-year to 6.5 Tcfe, driven by a 64% increase in liquids reserves. All-in finding and development cost averaged $0.86 per mcfe, while replacing 773% of production from drilling. Drill bit finding cost averaged $0.67 per mcfe. Production and reserves per share on a debt-adjusted basis increased 29% and 22%, respectively. This represents the seventh consecutive year of double-digit per-share growth for both production and reserves. Range’s unrisked unproved resource potential at year-end 2012 increased to 48—68 Tcfe; including 2.3—3.5 billion barrels of NGLs and crude oil.

Commenting, Jeff Ventura, the Company’s President and CEO, said, “Range had outstanding operational results for 2012. The Marcellus Shale play that Range discovered in 2004 became the largest producing field in the U.S. in 2012. Our million acre position in Pennsylvania provides for future growth with low reinvestment risk and strong rates of return. The Marcellus fueled our 29% increase in proved reserves while increasing our liquids reserves by 64%. Year-over-year production was up 36% while our liquids growth in the fourth quarter was 41% compared to the prior year quarter. Our cost structure per mcfe improved in each quarter of 2012. All-in finding and development costs continue to be under a dollar per mcfe with our three year average being $0.82 per mcfe and our three year reserve replacement averaging 815%. Consistent low finding costs are now visibly translating into lower DD&A rates in our financial statements, with $1.46 per mcfe in the fourth quarter. The lower rate will help drive future earnings. Our reserves per well in the Marcellus continue to improve as we gain additional production history and continue to optimize drilling and completion designs.

Looking ahead, 2013 should be even better than 2012. We expect to grow production in the 20% to 25% range utilizing our existing low-cost, high rate of return inventory. Range’s liquids production is expected to grow disproportionately greater than overall production in 2013 as we continue to focus the majority of our capital in our liquids-rich areas. With the continued ramp up in production volumes, we expect our cost structure to improve further as volumes grow faster than our absolute costs. Importantly, with our access to the growing global markets for NGLs through our innovative Mariner West and East projects we are increasing our price realizations and improving our profit margins. In addition to the Marcellus, our Horizontal Mississippian oil play is gaining substantial momentum and should add to our liquids production and reserves, while the Cline Shale, Wolfberry and Utica plays have exciting liquids potential. We are looking for 2013 to be a year of increasing production, reserves, cash flow and earnings which should translate into higher per share value for all Range shareholders.”

Financial Discussion

(Except for generally accepted accounting principles ("GAAP") reported amounts, specific expense categories exclude non-cash impairments, unrealized mark-to-market on derivatives, non-cash stock compensation and other items shown separately on the attached tables. We sold substantially all of our Barnett Shale properties in April 2011. Under GAAP, activity for our Barnett Shale properties was reclassified as "Discontinued operations." As a result, production, revenue and expenses associated with these properties were removed from continuing operations and reclassified as discontinued operations. In this release, supplemental Statements of Operations are presented to reconcile the changes to the prior-year periods for the reclassification of our Barnett Shale properties to discontinued operations. These supplemental non-GAAP tables present the reported GAAP amounts and the amounts that would have been reported if the Barnett Shale operations were included in continuing operations. All variances discussed in this release include the Barnett Shale operations as continuing operations in all prior year periods.)

Full Year 2012

GAAP revenues for 2012 totaled $1.5 billion (18% increase as compared to 2011), GAAP net cash provided from operating activities including changes in working capital reached $647 million ($4.04 per diluted share) and GAAP earnings were $13 million ($0.08 per diluted share) versus $58 million ($0.36 per diluted share) in 2011. 2012 results were driven by record high production and a decrease in unit costs, offset by a 23% decline in realized prices.

Non-GAAP revenues for 2012 totaled $1.4 billion (11% increase compared to 2011), cash flow from operations before changes in working capital, a non-GAAP measure, reached $756 million ($4.71 per diluted share versus consensus of $4.33 per share). Adjusted net income, a non-GAAP measure, was $148 million ($0.92 per diluted share for 2012 versus average First Call consensus estimates of $0.74 per share). Wellhead prices, after adjustment for all cash-settled hedges and derivatives, averaged $5.05 per mcfe. The Company's cost structure continued to improve as total unit costs decreased by $0.40 per mcfe or 9% as compared to the prior year. Direct operating expenses for the year averaged $0.41 per mcfe, a 32% decrease compared to the prior year. Depreciation, depletion and amortization expense decreased 7% to $1.62 per mcfe.

Fourth Quarter

GAAP revenues for the fourth quarter of 2012 totaled $458 million (51% increase as compared to fourth quarter 2011), GAAP net cash provided from operating activities including changes in working capital reached $186 million ($1.16 per diluted share) and GAAP earnings were $53 million ($0.32 per diluted share) versus a net loss of $3 million ($0.02 loss per diluted share) in 2011. Fourth quarter results were driven by a 35% increase in production and lower unit costs.

Non-GAAP revenues for fourth quarter 2012 totaled $418 million (19% increase compared to fourth quarter 2011), cash flow from operations before changes in working capital, a non-GAAP measure, reached $248 million ($1.54 per diluted share versus average First Call consensus estimates of $1.36 per share). Adjusted net income, a non-GAAP measure, was $73 million ($0.46 per diluted share for the fourth quarter 2012 versus average First Call consensus estimates of $0.29 per share). Wellhead prices, after adjustment for all cash-settled hedges and derivatives, averaged $5.35 per mcfe. The Company's total unit costs decreased by $0.36 per mcfe or 9% compared to the prior-year quarter. Direct operating expenses for the quarter were $0.38 per mcfe, a 16% decrease compared to the prior-year quarter. Depreciation, depletion and amortization expense decreased 14% to $1.46 per mcfe.

See "Non-GAAP Financial Measures" for a definition of each of these non-GAAP financial measures and tables that reconcile each of these non-GAAP measures to their most directly comparable GAAP financial measure.

Balance Sheet

During 2012, Range strengthened its balance sheet with the sale of its Ardmore Woodford and other miscellaneous properties for approximately $170 million. The sale proceeds were used to pay down the outstanding balance on its bank credit facility. At year-end 2012, following the redemption of $250 million in high-coupon 7.5% bonds, the Company had over $900 million of liquidity on its credit facility. Increasing quarterly cash flow and the proceeds from additional asset sales are expected to strengthen the balance sheet in 2013.

Recent Asset Sale Agreement

Range recently entered into an agreement to sell certain of its Permian Basin properties in southeast New Mexico and West Texas for a purchase price of $275 million. The sale is expected to close in April and is subject to customary closing conditions and purchase price adjustments. The properties being sold consist of approximately 7,000 net acres that are currently producing approximately 18 Mmcfe per day with approximately 70% being natural gas and 30% oil and NGLs. With this sale, the Company will have sold $2.3 billion in assets since 2004 while focusing its resources and personnel on the highest rate of return projects in the portfolio.

Hedging Status

Range hedges portions of its expected future production volumes to increase the predictability of its cash flow and to help maintain a strong, flexible financial position. Range currently has over 70% of its expected 2013 natural gas production hedged at a weighted average floor price of $4.18 per mcf. Similarly, Range has hedged more than 80% of its projected crude oil production at a floor price of $94.55 and more than 50% of its composite NGL production near current market prices. Please see Range's detailed hedging schedule posted at the end of the financial tables below and on its website at http://www.rangeresources.com.

Operational Discussion

Range has updated its investor presentation with acreage maps, updated economic sensitivity analysis and other financial and operational information. Please see www.rangeresources.com under the Investor Relations tab, "Presentations and Webcasts" area, for the presentation entitled, "Company Presentation—February 26, 2013."

Fourth quarter drilling expenditures of $234 million funded the drilling of 64 (54 net) wells. A 100% success rate was achieved. Drilling expenditures for 2012 totaled $1.36 billion, and Range drilled 298 (257 net) wells and 4 (4 net) recompletions during the year. Total capital spending for 2012 was $1.62 billion, including $189 million for leasehold. All-in finding and development cost for 2012 averaged $0.86 per mcfe, with drill bit reserve replacement of 773%. Drill bit only finding cost averaged $0.67 per mcfe.

Marcellus Shale –

Range continued to make significant progress in the Marcellus Shale during 2012 as we continued to grow production and reserves and delineate our sizable acreage position while expanding our current and future marketing and transportation capabilities for natural gas and NGLs. Range was able to reach its year-end production target of 600 Mmcfe per day net with approximately 75% of that production coming from the liquids-rich area of the play. Another milestone for Range in 2012 was the signing of two additional ethane transportation agreements, ATEX and Mariner East; the culmination of several years of planning. Mariner East will also transport propane to the northeast United States for both domestic consumption and export to international markets. Ethane exports to Canada under the first ethane sales agreement are expected to commence on time in mid-2013. These ethane sales are expected to allow Range to meet natural gas pipeline quality requirements for the foreseeable future and are expected to eliminate shut-in production risk in the liquids-rich area. Prior to the Mariner East pipeline being completed in 2014, Range is shipping propane by rail for export through the Marcus Hook port facility near Philadelphia to the international market. This innovative arrangement increased our NGL realizations in the fourth quarter of 2012. Additional exports of propane are planned for 2013.

Southern Marcellus Shale Division –

In early February, Range revised its estimated ultimate recovery ("EUR") for wells drilled in both the wet and super-rich areas of the Southern Marcellus Shale division. In the super-rich area, Range estimates wells will cost $5.1 million in development mode to drill and complete with a lateral length of 3,800 feet and 18 frac stages. This is expected to develop an EUR of 1.44 million barrels of oil equivalent that is 57% liquids (109 thousand barrels condensate, 715 thousand barrels NGLs and 3.7 Bcf gas). These projected well-level economics generate a 93% rate of return based on NYMEX "strip pricing" as of December 31, 2012. In the wet area, Range estimates wells will cost $4.9 million in development mode to drill and complete with a lateral length of 3,200 feet and 13 frac stages. This is expected to develop an EUR of 8.7 Bcf equivalent that is 49% liquids (27 thousand barrels condensate, 685 thousand barrels NGLs and 4.4 Bcf gas). These projected well-level economics generate a 78% rate of return based on NYMEX "strip pricing" as of December 31, 2012.

During the fourth quarter, the division brought online 30 horizontal wells in southwest Pennsylvania, 26 of which were located in the liquids-rich area of the play. The initial production rates of the new wells averaged 6.5 (5.1 net) Mmcfe per day consisting of 3.9 (3.0 net) Mmcf per day of natural gas and 432 (355 net) barrels of NGLs and condensate per day. Twenty-two of the wells brought online in the fourth quarter were in the super-rich area of the play, eight of which utilized reduced cluster spacing completions. In January, the division completed a three-well pad in the super-rich area at the combined 24-hour rate of 6,123 (5,220 net) boe per day that was 68% liquids (1,209 barrels condensate, 2,956 barrels NGLs and 11.7 Mmcf gas). In February, the division completed two wells on another super-rich area pad at the combined 24-hour rate of 6,866 (5,685 net) boe per day that was 59% liquids (793 barrels condensate, 3,260 barrels NGLs and 16.9 Mmcf gas).

In the southwest Marcellus, the Company drilled and cased 25 wells in the fourth quarter and the Company turned to sales 30 wells. As a result, the Company's backlog of uncompleted wells and wells waiting on pipeline connection declined to 58. The division is currently utilizing six rigs and plans to maintain similar activity levels throughout 2013.

Northern Marcellus Shale Division –

In the northeast Marcellus, Range drilled and cased eight wells in the fourth quarter. A significant well was drilled in Lycoming County that produced at a 24-hour rate of 14.2 (12.2 net) Mmcf per day from a lateral of 2,475 feet and nine frac stages. In total, 11 wells were turned to sales in the fourth quarter. As a result, the Company's backlog of uncompleted wells and wells waiting on pipeline connection declined to 28 wells at year-end. We are currently running two rigs in northeast Pennsylvania and anticipate running one or two rigs for 2013 to maintain continuous drilling commitments under the leases.

In the Bradford County participating area with Talisman, there were a total of 17 (4.5 net) wells producing, 13 (3.5 net) wells waiting on completion and 24 (6.5 net) wells waiting on pipeline.

In northwest Pennsylvania, Range drilled its first Utica well (50% WI) on its 181,000 net acres. The well encountered 285 feet of Utica/Point Pleasant pay at a depth of approximately 7,000 feet. The well confirmed that we are in the wet gas window and have good pressure. Diagnostics indicate that the well was not effectively stimulated and to date has tested at just over 1.4 Mmcfe per day. However, we are encouraged by the well data and we are monitoring offset activity as we choose the timing of our next test.

Midcontinent Division –

Midcontinent operations in the fourth quarter focused on the Horizontal Mississippian play in Oklahoma and Kansas along the Nemaha Ridge. Recently, the division drilled a well with a 24-hour initial production rate of 812 (710 net) boe per day that was 82% liquids (458 barrels oil, 207 barrels NGLs and 0.9 Mmcf gas) from a lateral that was limited to 2,342 feet due to unit size. With five rigs currently running, completion activity is expected to build late in the first quarter of 2013.

During the fourth quarter, 9 (8.2 net) wells were turned to sales with average lateral lengths of 3,800 feet and 20 frac stages. Average 7-day rates for the completions were 482 (363 net) boe per day with 76% liquids. Additionally, we now have 30-day rates on two of our previously announced 1,000+ boe per day wells that were drilled in the fourth quarter. The Dakota #9-5S achieved a 30-day average rate 802 (654 net) boe per day (348 barrels oil, 265 barrels NGLs and 1.1 Mmcf gas). The Troche #1-4N had a 30-day average of 615 (372 net) boe per day (361 barrels oil, 148 barrels NGLs and 0.6 Mmcf gas). The current leasehold position of approximately 160,000 net acres is expected to be held by production with the drilling schedule we have planned through 2015. A total of 51 Horizontal Mississippian and 17 saltwater disposal wells are expected to be drilled in 2013.

In addition, a one rig program is anticipated in the Texas Panhandle for most of 2013 where Range has had some early success drilling Horizontal St. Louis wells. Another St. Louis well was completed in the fourth quarter for 10.9 (4.3 net) Mmcfe per day (7.8 Mmcf gas, 203 barrels oil and 314 barrels NGLs). Six to eight additional test wells are planned for drilling in 2013.

Permian Division –

Range's Permian team is targeting the Wolfberry and Cline Shale oil plays in West Texas. In the Wolfberry, Range completed three additional wells in the fourth quarter. The average 24-hour initial production rate for these wells was 521 (406 net) boe per day with 78% liquids (301 barrels oil, 104 barrels NGLs and 0.7 Mmcf gas). In addition to higher initial rates in the Wolfberry, drill and completion costs were reduced to $2.4 million for the most recent three wells. The six Wolfberry wells drilled to date are producing above our initial forecasts. In the Cline Shale, Range completed its third well in the fourth quarter. The initial 24-hour rate on this well was 620 (511 net) boe per day with 77% liquids (231 barrels oil, 249 barrels NGLs and 0.8 Mmcf gas). Range will continue to test these plays throughout 2013, while monitoring industry activity in an area where Range has approximately 100,000 net acres that are over 90% held by production.

Southern Appalachia Division –

The Southern Appalachia Division continued development of multi-pay horizons on its 350,000 (235,000 net) acre position in Virginia during the fourth quarter. The division had one drilling rig and one completion rig running in the quarter and drilled 2 (2 net) tight gas sand wells and turned online 4 (4 net) wells. Despite spending only $29 million in capital in 2012, (down approximately 50% versus prior year), the division's 2012 production rate was up 2% compared to 2011.

Guidance – First Quarter 2013

Production per day Guidance:

Production growth for 2013 is targeted at 20%-25% year-over-year. Production for the first quarter of 2013 is expected to range between 845 to 850 Mmcfe per day. Liquids are expected to be approximately 20% of first quarter production. Daily liquids production is expected to be slightly lower in the first quarter of 2013 compared to fourth quarter of 2012. This is the result of completion timing and the mix of wells being turned on. In the winter the Company typically completes fewer wells due to weather, as is typical in Appalachia. As a result of fewer completions and fewer wells being turned on, first quarter production will be relatively flat, while liquids will decline slightly. The relatively small set of wells being turned to sales in first quarter has some high-return dry gas wells which keeps that portion of the production growing in first quarter 2013. Range expects completions and wells being turned to sales to accelerate throughout the rest of the year and that activity is expected to be weighted toward the liquids-rich areas. As a result, Range is expecting liquids production growth during 2013 to be greater than the 20%-25% year-over-year overall production growth target.

Expense per mcfe Guidance:

Direct operating expense:	$0.38 - $0.40 per mcfe
Transportation, gathering and compression expense (a):	$0.75 - $0.77 per mcfe
Production tax expense (b):	$0.14 - $0.15 per mcfe
Exploration expense:	$18 - $20 million
Unproved property impairment expense:	$15 - $17 million
G&A expense:	$0.40 - $0.42 per mcfe
Interest expense:	$0.55 - $0.57 per mcfe
DD&A expense:	$1.46 - $1.48 per mcfe

(a) Prior to year-end 2011 this expense was netted against revenue. Please refer to Table 6 of the 4Q 2012 Supplement Tables for historical detail of this expense by product.

(b) Production tax expense in first quarter should equal approximately $0.07 per mcfe plus an estimated $6.2 million for the Pennsylvania impact fee. Total production tax expense including the impact fee is expected to be $0.14—$0.15 per mcfe.

Differential Pricing History (c)

	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012	4Q 2012
Natural Gas	$ 0.26	$ 0.07	($ 0.02)	($ 0.13)	($ 0.03)	$ 0.18
NGL (% of WTI NYMEX)	54%	54%	48%	39%	33%	43%
Oil (% of WTI NYMEX)	91%	92%	88%	91%	90%	89%

(c) Differentials based on pre-hedge pricing, excluding transportation, gathering and compression expense.

Conference Call Information

A conference call to review the financial results is scheduled on Wednesday, February 27 at 9:00 a.m. ET. To participate in the call, please dial 877-407-0778 and ask for the Range Resources 2012 financial results conference call. A replay of the call will be available through March 29. To access the phone replay dial 877-660-6853. The conference ID is 409202.

A simultaneous webcast of the call may be accessed over the Internet at http://www.rangeresources.com/ or http://www.vcall.com/. The webcast will be archived for replay on the Company’s website until March 29.

Non-GAAP Financial Measures:

Adjusted net income comparable to analysts' estimates as set forth in this release represents income from operations before income taxes adjusted for certain non-cash items (detailed below and in the accompanying table) less income taxes. We believe adjusted net income comparable to analysts' estimates is calculated on the same basis as analysts' estimates and that many investors use this published research in making investment decisions useful in evaluating operational trends of the Company and its performance relative to other oil and gas producing companies. Diluted earnings per share (adjusted) as set forth in this release represents adjusted net income comparable to analysts' estimates on a diluted per share basis. A table is included which reconciles income from operations to adjusted net income comparable to analysts' estimates and diluted earnings per share (adjusted). On its website, the Company provides additional comparative information on prior periods.

Cash flow from operations before changes in working capital as defined in this release represents net cash provided by operations before changes in working capital and exploration expense adjusted for certain non-cash compensation items. Cash flow from operations before changes in working capital is widely accepted by the investment community as a financial indicator of an oil and gas company's ability to generate cash to internally fund exploration and development activities and to service debt. Cash flow from operations before changes in working capital is also useful because it is widely used by professional research analysts in valuing, comparing, rating and providing investment recommendations of companies in the oil and gas exploration and production industry. In turn, many investors use this published research in making investment decisions. Cash flow from operations before changes in working capital is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operations, investing, or financing activities as an indicator of cash flows, or as a measure of liquidity. A table is included which reconciles Net cash provided by operations to Cash flow from operations before changes in working capital as used in this release. On its website, the Company provides additional comparative information on prior periods for cash flow, cash margins and non-GAAP earnings as used in this release.

The cash prices realized for oil and natural gas production including the amounts realized on cash-settled derivatives and net of transportation, gathering and compression expense is a critical component in the Company's performance tracked by investors and professional research analysts in valuing, comparing, rating and providing investment recommendations and forecasts of companies in the oil and gas exploration and production industry. In turn, many investors use this published research in making investment decisions. Due to the GAAP disclosures of various derivative transactions and third party transportation, gathering and compression expense, such information is now reported in various lines of the income statement. The Company believes that it is important to furnish a table reflecting the details of the various components of each income statement line to better inform the reader of the details of each amount and provide a summary of the realized cash-settled amounts and third party transportation, gathering and compression expense which historically were reported as natural gas, NGLs and oil sales. This information will serve to bridge the gap between various readers' understanding and fully disclose the information needed.

Range has disclosed two primary metrics in this release to measure our ability to establish a long-term trend of adding reserves at a reasonable cost – a reserve replacement ratio and finding and development cost per unit. The reserve replacement ratio is an indicator of our ability to replace annual production volumes and grow our reserves. It is important to economically find and develop new reserves that will offset produced volumes and provide for future production given the inherent decline of hydrocarbon reserves as they are produced. We believe the ability to develop a competitive advantage over other natural gas and oil companies is dependent on adding reserves in our core areas at lower costs than our competition. The reserve replacement ratio is calculated by dividing production for the year into the total of proved extensions, discoveries and additions and proved reserves added by performance revisions.

Finding and development cost per unit is a non-GAAP metric used in the exploration and production industry by companies, investors and analysts. The calculations presented by the Company are based on costs incurred excluding asset retirement obligations and divided by proved reserve additions (extensions, discoveries and additions shown in the summary of changes in proved reserves table) adjusted for the changes in proved reserves for performance revisions (drill bit) and for performance and price revisions (all-in). This calculation does not include the future development costs required for the development of proved undeveloped reserves. The SEC method of computing finding costs contains additional cost components and results in a higher number. A reconciliation of the two methods is shown on our website at www.rangeresources.com.

The reserve replacement ratio and finding and development cost per unit are statistical indicators that have limitations, including their predictive and comparative value. As an annual measure, the reserve replacement ratio can be limited because it may vary widely based on the extent and timing of new discoveries and the varying effects of changes in prices and well performance. In addition, since the reserve replacement ratio and finding and development cost per unit do not consider the cost or timing of future production of new reserves, such measures may not be an adequate measure of value creation. These reserves metrics may not be comparable to similarly titled measurements used by other companies.

Year-end pre-tax discounted present value is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of pre-tax discounted present value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We further believe investors and creditors use pre-tax discounted present value as a basis for comparison of the relative size and value of our reserves as compared with other companies. Range's pre-tax discounted present value as of December 31, 2012 may be reconciled to its standardized measure of discounted future net cash flows as of December 31, 2012 by reducing Range's pre-tax discounted present value by the discounted future income taxes associated with such reserves.

Reconciliation of PV-10
($ in millions) (unaudited)

	December 31, 2012
Standardized measure of discounted future net of cash flows	$ 3,224
Discounted future cash flows for income taxes	736
Discounted future net cash flows before income taxes (PV-10)	$ 3,960

Range has disclosed a debt-adjusted per share metric in this release to measure per-share growth of production and reserves. This debt-adjusted metric keeps the debt-to-capitalization ratio unchanged during the calculation period. To achieve a constant debt-to-capitalization ratio, the share count is adjusted to increase/decrease equity from the actual end-of-year to the beginning of period level debt-to-cap. This adjustment is made by dividing the necessary increase/decrease in equity by the average common share price during the year for production (year-end price for reserves) to arrive at shares issued/repurchased. The production or reserves are then divided by this adjusted share count to reach the debt-adjusted per share results.

Hedging and Derivatives

In this news release, Range has reclassified within total revenues its financial reporting of the cash settlement of its commodity derivatives. Under this presentation those hedges considered "effective" under ASC 815 are included in "Natural gas, NGLs and oil sales" when settled. For those hedges designated to regions where the historical correlation between NYMEX and regional prices is "non-highly effective" or is "volumetric ineffective" due to sale of the underlying reserves, they are deemed to be "derivatives" and the cash settlements are included in a separate line item shown as "Derivative fair value income (loss)" in the consolidated statements of operations included in the Company's Form 10-K along with the change in mark-to-market valuations of such unrealized derivatives. The Company has provided additional information regarding natural gas, NGLs and oil sales in a supplemental table included with this release, which would correspond to amounts shown by analysts for natural gas, NGLs and oil sales realized, including cash-settled derivatives.

RANGE RESOURCES CORPORATION (NYSE: RRC) is a leading independent oil and natural gas producer with operations focused in Appalachia and the southwest region of the United States. The Company pursues an organic growth strategy targeting high return, low-cost projects within its large inventory of low risk, development drilling opportunities. The Company is headquartered in Fort Worth, Texas. More information about Range can be found at http://www.rangeresources.com/ and http://www.myrangeresources.com/.

Except for historical information, statements made in this release such as future growth in production, reserves, cash flow, earnings and per-share value, low-reinvestment risk, future rates of return, continued drilling improvements, disproportionate growth in liquids production and reserves, cost structure improvements, future price realizations, expected sales proceeds, planned exports, estimated cost, and expected drilling plans are 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. These statements are based on assumptions and estimates that management believes are reasonable based on currently available information; however, management's assumptions and Range's future performance are subject to a wide range of business risks and uncertainties and there is no assurance that these goals and projections can or will be met. Any number of factors could cause actual results to differ materially from those in the forward-looking statements, including, but not limited to, the volatility of oil and gas prices, the results of our hedging transactions, the costs and results of drilling and operations, the timing of production, mechanical and other inherent risks associated with oil and gas production, weather, the availability of drilling equipment, changes in interest rates, litigation, uncertainties about reserve estimates and environmental risks. Range undertakes no obligation to publicly update or revise any forward-looking statements. Further information on risks and uncertainties is available in Range's filings with the Securities and Exchange Commission ("SEC"), which are incorporated by reference.

The SEC permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions as well as the option to disclose probable and possible reserves. Range has elected not to disclose the Company's probable and possible reserves in its filings with the SEC. Range uses certain broader terms such as "resource potential," or "unproved resource potential,""upside" and "EURs per well" or other descriptions of volumes of resources potentially recoverable through additional drilling or recovery techniques that may include probable and possible reserves as defined by the SEC's guidelines. Range has not attempted to distinguish probable and possible reserves from these broader classifications. The SEC's rules prohibit us from including in filings with the SEC these broader classifications of reserves. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. Unproved resource potential refers to Range's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques and have not been reviewed by independent engineers. Unproved resource potential does not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System and does not include proved reserves. Area wide unproven, unrisked resource potential has not been fully risked by Range's management. "EUR," or estimated ultimate recovery, refers to our management's internal estimates of per well hydrocarbon quantities that may be potentially recovered from a hypothetical future well completed as a producer in the area. These quantities do not necessarily constitute or represent reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or the SEC's oil and natural gas disclosure rules. Our management estimated these EURs based on our previous operating experience in the given area and publicly available information relating to the operations of producers who are conducting operating in these areas. Actual quantities that may be ultimately recovered from Range's interests will differ substantially. Factors affecting ultimate recovery include the scope of Range's drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, field spacing rules, recoveries of gas in place, length of horizontal laterals, actual drilling results, including geological and mechanical factors affecting recovery rates and other factors. Estimates of resource potential may change significantly as development of our resource plays provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. Investors are urged to consider closely the disclosure in our most recent Annual Report on Form 10-K, available from our website at www.rangeresources.com or by written request to 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. You can also obtain this Form 10-K by calling the SEC at 1-800-SEC-0330.

2013-5

SOURCE: Range Resources Corporation

Investor Contacts:

Rodney Waller, Senior Vice President
817-869-4258

David Amend, Investor Relations Manager
817-869-4266

Laith Sando, Senior Financial Analyst
817-869-4267

Michael Freeman, Financial Analyst
817-869-4264

or

Media Contact:

Matt Pitzarella, Director of Corporate Communications
724-873-3224

www.rangeresources.com

STATEMENTS OF OPERATIONS

Based on GAAP reported earnings with additional
details of items included in each line in Form 10-K
(Unaudited, in thousands, except per share data)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2012	2011	%	2012	2011	%
Revenues and other income:						
Natural gas, NGLs and oil sales (a)	$398,688	$331,720		$1,351,694	$1,173,266	
Derivative cash settlements gain (loss) (a) (b)	16,706	13,800		38,700	22,142	
Change in mark-to-market on unrealized derivatives gain (loss) (b)	(24,117)	(51,331)		5,958	15,762	
Ineffective hedging (loss) gain (b)	1,840	(348)		(3,221)	2,183	
Gain (loss) on sale of properties	61,836	3,539		49,132	2,259	
Brokered natural gas and marketing (c)	2,948	3,770		15,078	12,693	
Equity method investment (c)	(177)	356		(372)	(1,043)	
Other (c)	314	1,712		735	3,380	
Total revenues and other income	458,038	303,218	51%	1,457,704	1,230,642	18%
Costs and expenses:						
Direct operating	29,446	25,347		113,490	110,985	
Direct operating – non-cash stock compensation (d)	768	571		2,415	1,987	
Transportation, gathering and compression	55,281	34,576		192,445	120,755	
Production and ad valorem taxes	9,380	5,920		41,912	26,666	
Pennsylvania impact fee —prior year	501	—		25,208	—	
Brokered natural gas and marketing	4,542	2,803		18,669	10,531	
Brokered natural gas and marketing – non-cash stock- based compensation (d)	452	348		1,765	1,455	
Exploration	17,021	24,042		65,758	77,259	
Exploration – non-cash stock compensation (d)	1,001	940		4,049	4,108	
Abandonment and impairment of unproved properties	21,230	27,639		125,278	79,703	
General and administrative	31,402	32,647		125,355	113,461	
General and administrative – non-cash stock compensation (d)	13,786	8,756		44,541	36,244	
General and administrative – lawsuit settlements	644	302		3,167	540	
General and administrative – bad debt expense	750	500		750	946	
Deferred compensation plan (e)	(14,352)	9,640		7,203	43,209	
Interest expense	44,708	34,709		168,798	125,052	
Loss on early extinguishment of debt	11,063	—		11,063	18,576	
Depletion, depreciation and amortization	113,216	97,092		445,228	341,221	
Impairment of proved properties and other assets	34,273	—		35,554	38,681	
Total costs and expenses	375,112	305,832	23%	1,432,648	1,152,379	24%
Income (loss) from continuing operations before income taxes	82,926	(2,614)	3272%	25,056	78,263	-68%
Income tax expense (benefit):						
Current	(1,778)	636		(1,778)	637	
Deferred	31,742	(425)		13,832	34,920	
	29,964	211		12,054	35,557	
Income (loss) from continuing operations	52,962	(2,825)	1975%	13,002	42,706	-70%
Discontinued operations, net of tax	—	(164)		—	15,320	
Net income (loss)	$ 52,962	$ (2,989)	1872%	$ 13,002	$ 58,026	-78%
Income (Loss) Per Common Share:						
Basic-Income (loss) from continuing operations	$ 0.33	$ (0.02)		$ 0.08	$ 0.26	
Discontinued operations	—	—		—	0.10	
Net income (loss)	$ 0.33	$ (0.02)	1750%	$ 0.08	$ 0.36	-78%
Diluted-Income (loss) from continuing operations	$ 0.32	$ (0.02)		$ 0.08	$ 0.26	
Discontinued operations	—	—		—	0.10	
Net income (loss)	$ 0.32	$ (0.02)	1700%	$ 0.08	$ 0.36	-78%
Weighted average common shares outstanding, as reported:						
Basic	159,832	158,413	1%	159,431	158,030	1%
Diluted	160,559	158,413	1%	160,307	159,441	1%

(a) See separate natural gas, NGLs and oil sales information table.
(b) Included in Derivative fair value (loss) income in the 10-K.
(c) Included in Brokered natural gas, marketing and other revenues in the 10-K.
(d) Costs associated with stock compensation and restricted stock amortization, which have been reflected in the categories associated with the direct personnel costs, which are combined with the cash costs in the 10-K.
(e) Reflects the change in market value of the vested Company stock held in the deferred compensation plan.

RANGE RESOURCES CORPORATION

STATEMENTS OF OPERATIONS
Restated for Barnett discontinued operations, a non-GAAP presentation
(Unaudited, in thousands, except per share data)

	Three Months Ended December 31, 2012			Three Months Ended December 31, 2011		
	As reported	Barnett Discontinued Operations	Including Barnett Ops	As reported	Barnett Discontinued Operations	Including Barnett Ops
Revenues and other income:						
Natural gas, NGLs and oil sales	$398,688	—	$398,688	$331,720	$ 188	$331,908
Derivative cash settlements gain (loss)	16,706	—	16,706	13,800	—	13,800
Change in mark-to-market on unrealized derivatives gain (loss)	(24,117)	—	(24,117)	(51,331)	—	(51,331)
Ineffective hedging gain (loss)	1,840	—	1,840	(348)	—	(348)
Gain (loss) on sale of properties	61,836	—	61,836	3,539	—	3,539
Brokered natural gas and marketing	2,948	—	2,948	3,770	—	3,770
Equity method investment	(177)	—	(177)	356	(81)	275
Interest and other	314	—	314	1,712	—	1,712
	458,038	—	458,038	303,218	107	303,325
Costs and expenses:						
Direct operating	29,446	—	29,446	25,347	245	25,592
Direct operating – non-cash stock-based compensation	768	—	768	571	—	571
Transportation, gathering and compression	55,281	—	55,281	34,576	17	34,593
Production and ad valorem taxes	9,380	—	9,380	5,920	103	6,023
Pennsylvania impact fee – prior year	501	—	501	—	—	—
Brokered natural gas and marketing	4,542	—	4,542	2,803	—	2,803
Brokered natural gas and marketing non-cash stock-based comp	452	—	452	348	—	348
Exploration	17,021	—	17,021	24,042	—	24,042
Exploration – non-cash stock-based compensation	1,001	—	1,001	940	—	940
Abandonment and impairment of unproved properties	21,230	—	21,230	27,639	—	27,639
General and administrative	31,402	—	31,402	32,647	—	32,647
General and administrative – non-cash stock-based compensation	13,786	—	13,786	8,756	—	8,756
General and administrative – lawsuit settlements	644	—	644	302	—	302
General and administrative – bad debt expense	750	—	750	500	—	500
Deferred compensation plan	(14,352)	—	(14,352)	9,640	—	9,640
Interest expense	44,708	—	44,708	34,709	—	34,709
Loss on early extinguishment of debt	11,063	—	11,063	—	—	—
Depletion, depreciation and amortization	113,216	—	113,216	97,092	—	97,092
Impairment of proved properties and other assets	34,273	—	34,273	—	—	—
	375,112	—	375,112	305,832	365	306,197
Income (loss) from continuing operations before income taxes	82,926	—	82,926	(2,614)	(258)	(2,872)
Income tax expense (benefit):						
Current	(1,778)	—	(1,778)	636	—	636
Deferred	31,742	—	31,742	(425)	(94)	(519)
	29,964	—	29,964	211	(94)	117
Income (loss) from continuing operations	52,962	—	52,962	(2,825)	(164)	(2,989)
Discontinued operations-Barnett Shale, net of tax	—	—	—	(164)	164	—
Net income (loss)	$ 52,962	—	$ 52,962	$ (2,989)	—	$ (2,989)
OPERATING HIGHLIGHTS						
Average daily production:						
Natural gas (mcf)	655,224	—	655,224	490,731	289	491,020
NGLs (bbl)	21,652	—	21,652	16,886	45	16,931
Oil (bbl)	9,863	—	9,863	5,407	2	5,409
Gas equivalents (mcfe)	844,314	—	844,314	624,491	568	625,059
Average prices realized before transportation, gathering and compression:						
Natural gas (mcf)	$ 4.21	—	$ 4.21	$ 4.81	—	$ 4.81
NGLs (bbl)	$ 43.56	—	$ 43.56	$ 55.69	—	$ 55.68
Oil (bbl)	$ 82.30	—	$ 82.30	$ 83.71	—	$ 83.71
Gas equivalents (mcfe)	$ 5.35	—	$ 5.35	$ 6.01	—	$ 6.01
Direct operating cash costs per mcfe:						
Field expenses	$ 0.36	—	$ 0.36	$ 0.42	—	$ 0.43
Workovers	0.02	—	0.02	0.02	—	0.02
Total operating costs	$ 0.38	—	$ 0.38	$ 0.44	—	$ 0.45
Transportation, gathering and compression cost per mcf:	$ 0.71	—	$ 0.71	$ 0.60	$ 0.33	$ 0.60

RANGE RESOURCES CORPORATION

STATEMENTS OF OPERATIONS

Restated for Barnett discontinued operations, a non-GAAP presentation
(Unaudited, in thousands, except per share data)

	Twelve Months Ended December 31, 2012			Twelve Months Ended December 31, 2011		
	As reported	Barnett Discontinued Operations	Including Barnett Ops	As reported	Barnett Discontinued Operations	Including Barnett Ops
Revenues and other income:						
Natural gas, NGLs and oil sales	$1,351,694	—	$1,351,694	$1,173,266	$ 59,185	$1,232,451
Derivative cash settlements gain (loss)	38,700	—	38,700	22,142	—	22,142
Change in mark-to-market on unrealized derivatives gain (loss)	5,958	—	5,958	15,762	—	15,762
Ineffective hedging gain (loss)	(3,221)	—	(3,221)	2,183	—	2,183
Gain (loss) on sale of properties	49,132	—	49,132	2,259	—	2,259
Brokered natural gas and marketing	15,078	—	15,078	12,693	6	12,699
Equity method investment	(372)	—	(372)	(1,043)	4,771	3,728
Interest and other	735	—	735	3,380	4	3,384
	1,457,704	—	1,457,704	1,230,642	63,966	1,294,608
Costs and expenses:						
Direct operating	113,490	—	113,490	110,985	10,035	121,020
Direct operating – non-cash stock-based compensation	2,415	—	2,415	1,987	45	2,032
Transportation, gathering and compression	192,445	—	192,445	120,755	5,257	126,012
Production and ad valorem taxes	41,912	—	41,912	27,666	1,309	28,975
Pennsylvania impact fee – prior year	25,208	—	25,208	—	—	—
Brokered natural gas and marketing	18,669	—	18,669	10,531	—	10,531
Brokered natural gas and marketing non-cash stock-based comp	1,765	—	1,765	1,455	—	1,455
Exploration	65,758	—	65,758	77,259	37	77,296
Exploration – non-cash stock-based compensation	4,049	—	4,049	4,108	—	4,108
Abandonment and impairment of unproved properties	125,278	—	125,278	79,703	—	79,703
General and administrative	125,355	—	125,355	113,461	—	113,461
General and administrative – non-cash stock-based compensation	44,541	—	44,541	36,244	—	36,244
General and administrative – lawsuit settlements	3,167	—	3,167	540	—	540
General and administrative – bad debt expense	750	—	750	946	—	946
Deferred compensation plan	7,203	—	7,203	43,209	—	43,209
Interest expense	168,798	—	168,798	125,052	14,791	139,843
Loss on early extinguishment of debt	11,063	—	11,063	18,576	—	18,576
Depletion, depreciation and amortization	445,228	—	445,228	341,221	8,894	350,115
Impairment of proved properties and other assets	35,554	—	35,554	38,681	—	38,681
	1,432,648	—	1,432,648	1,152,379	40,368	1,192,747
Income (loss) from continuing operations before income taxes	25,056	—	25,056	78,263	23,598	101,861
Income tax expense (benefit):						
Current	(1,778)	—	(1,778)	637	—	637
Deferred	13,832	—	13,832	34,920	8,278	43,198
	12,054	—	12,054	35,557	8,278	43,835
Income (loss) from continuing operations	13,002	—	13,002	42,706	15,320	58,026
Discontinued operations-Barnett Shale, net of tax	—	—	—	15,320	(15,320)	—
Net income (loss)	$ 13,002	—	$ 13,002	$ 58,026	—	$ 58,026
OPERATING HIGHLIGHTS						
Average daily production:						
Natural gas (mcf)	591,679	—	591,679	397,825	32,316	430,141
NGLs (bbl)	19,036	—	19,036	14,664	605	15,269
Oil (bbl)	7,790	—	7,790	5,369	23	5,392
Gas equivalents (mcfe)	752,637	—	752,637	518,019	36,079	554,098
Average prices realized before transportation, gathering and compression:						
Natural gas (mcf)	$ 3.95	—	$ 3.95	$ 5.22	—	$ 5.13
NGLs (bbl)	$ 42.60	—	$ 42.60	$ 52.03	—	$ 51.79
Oil (bbl)	$ 83.64	—	$ 83.64	$ 81.34	—	$ 81.38
Gas equivalents (mcfe)	$ 5.05	—	$ 5.05	$ 6.32	—	$ 6.20
Direct operating cash costs per mcfe:						
Field expenses	$ 0.39	—	$ 0.39	$ 0.57	$ 0.74	$ 0.58
Workovers	0.02	—	0.02	0.02	0.02	0.02
Total operating costs	$ 0.41	—	$ 0.41	$ 0.59	$ 0.76	$ 0.60
Transportation, gathering and compression cost per mcf:	$ 0.70	—	$ 0.70	$ 0.85	$ 0.53	$ 0.83

RANGE RESOURCES CORPORATION

BALANCE SHEETS
(Audited, in thousands)

	December 31, 2012	December 31, 2011
Assets		
Current assets	$ 190,062	$ 141,342
Current unrealized derivative gain	137,552	173,921
Natural gas and oil properties	6,096,184	5,157,566
Transportation and field assets	41,567	52,678
Other	263,370	319,963
	$6,728,735	$5,845,470
Liabilities and Stockholders' Equity		
Current liabilities	$ 448,202	$ 506,274
Current asset retirement obligation	2,470	5,005
Current unrealized derivative loss	4,471	—
Current liabilities of discontinued operations	—	653
Bank debt	739,000	187,000
Subordinated notes	2,139,185	1,787,967
Total long-term debt	2,878,185	1,974,967
Deferred tax liability	698,302	710,490
Unrealized derivative loss	3,463	173
Deferred compensation liability	187,604	169,188
Long-term asset retirement obligation and other	148,646	86,300
Common stock and retained earnings	2,278,243	2,242,136
Treasury stock	(4,760)	(6,343)
Accumulated other comprehensive income	83,909	156,627
Total stockholders' equity	2,357,392	2,392,420
	$6,728,735	$5,845,470

CASH FLOWS FROM OPERATING ACTIVITIES

(Unaudited, in thousands)

	Three Months Ended December 31, 2012	Three Months Ended December 31, 2011	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011
Net income (loss)	$ 52,962	$ (2,989)	$ 13,002	$ 58,026
Adjustments to reconcile net income to net cash provided from operating activities:				
(Income) loss discontinued operations	—	164	—	(15,320)
(Gain) loss from equity investment, net of distributions	3,418	(1,906)	5,670	16,871
Deferred income tax expense (benefit)	31,742	(425)	13,832	34,920
Depletion, depreciation, amortization and proved property impairment	147,489	97,092	480,782	379,902
Exploration dry hole costs	9	1,372	841	3,888
Abandonment and impairment of unproved properties	21,230	27,639	125,278	79,703
Mark-to-market loss (gain) on oil and gas derivatives not designated as hedges	24,118	51,331	(5,958)	(15,762)
Unrealized derivatives (gain) loss	(1,840)	348	3,221	(2,183)
Allowance for bad debts	750	500	750	946
Amortization of deferred financing costs, loss on extinguishment of debt, and other	17,195	1,705	23,165	25,458
Deferred and stock-based compensation	1,563	20,220	60,136	86,979
Gain (loss) on sale of assets and other	(61,836)	(3,539)	(49,132)	(2,259)
Changes in working capital:				
Accounts receivable	(39,507)	(17,756)	(48,986)	(52,112)
Inventory and other	(1,982)	(10)	(7,376)	865
Accounts payable	2,580	8,000	13,654	738
Accrued liabilities and other	(11,915)	(413)	18,220	9,540
Net changes in working capital	(50,824)	(10,179)	(24,488)	(40,969)
Net cash provided from continuing operations	185,976	181,333	647,099	610,200
Net cash provided from discontinued operations	—	1,959	—	21,437
Net cash provided from operating activities	$185,976	$183,292	$647,099	$631,637

RECONCILIATION OF NET CASH PROVIDED FROM OPERATING ACTIVITIES, AS REPORTED, TO CASH FLOW FROM OPERATIONS BEFORE CHANGES IN WORKING CAPITAL, a non-GAAP measure

(Unaudited, in thousands)

	Three Months Ended December 31, 2012	Three Months Ended December 31, 2011	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011
Net cash provided from operating activities, as reported	$185,976	$183,292	$647,099	$631,637
Net changes in working capital from continuing operations	50,824	10,179	24,488	40,969
Exploration expense	12,873	22,670	60,778	73,371
Lawsuit settlements	644	302	3,167	540
Equity method investment distribution / intercompany elimination	(3,241)	1,550	(5,298)	(15,828)
Prior year Pennsylvania impact fee	501	—	25,208	—
Non-cash compensation adjustment	292	85	295	270
Net changes in working capital from discontinued operations and other	—	(2,136)	—	6,366
Cash flow from operations before changes in working capital, a non-GAAP measure	$247,869	$215,942	$755,737	$737,325

ADJUSTED WEIGHTED AVERAGE SHARES OUTSTANDING

(Unaudited, in thousands)

	Three Months Ended December 31, 2012	Three Months Ended December 31, 2011	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011
Basic:				
Weighted average shares outstanding	162,627	161,253	162,306	160,906
Stock held by deferred compensation plan	(2,795)	(2,840)	(2,875)	(2,876)
Adjusted basic	159,832	158,413	159,431	158,030
Dilutive:				
Weighted average shares outstanding	162,627	161,253	162,306	160,906
Anti-dilutive or dilutive stock options under treasury method	(2,068)	(2,840)	(1,999)	(1,465)
Adjusted dilutive	160,559	158,413	160,307	159,441

RANGE RESOURCES CORPORATION

RECONCILIATION OF NATURAL GAS, NGLs AND OIL SALES AND DERIVATIVE FAIR VALUE INCOME (LOSS) TO CALCULATED CASH REALIZED NATURAL GAS, NGLs AND OIL PRICES WITH AND WITHOUT THIRD PARTY TRANSPORTATION, GATHERING AND COMPRESSION FEES
non-GAAP measures

(Unaudited, in thousands, except per unit data)	As Reported, GAAP Excludes Barnett Operations Three Months Ended December 31, 2012	2011	%	Non-GAAP Includes Barnett Operations Three Months Ended December 31, 2012	2011	%
Natural gas, NGLs and oil sales components:						
Natural gas sales	$ 213,348	$ 165,300		$ 213,348	$ 165,256	
NGLs sales	75,468	79,995		75,468	80,215	
Oil sales	71,245	43,489		71,245	43,501	
Cash-settled hedges (effective):						
Natural gas	39,584	42,936		39,584	42,936	
Crude oil	(957)	—		(957)	—	
Total natural gas, NGLs and oil sales, as reported	$ 398,688	$ 331,720	20%	$ 398,688	$ 331,908	20%
Derivative fair value income (loss) components:						
Cash-settled derivatives (ineffective):						
Natural gas	$ 1,026	$ 9,122		$ 1,026	$ 9,122	
NGLs	11,295	6,524		11,295	6,524	
Crude Oil	4,385	(1,847)		4,385	(1,847)	
Change in mark-to-market on unrealized derivatives	(24,117)	(51,331)		(24,117)	(51,331)	
Unrealized ineffectiveness	1,840	(348)		1,840	(348)	
Total derivative fair value income (loss), as reported	$ (5,571)	$ (37,880)		$ (5,571)	$ (37,880)	
Natural gas, NGLs and oil sales, including all cash-settled derivatives (c):						
Natural gas sales	$ 253,958	$ 217,358		$ 253,958	$ 217,314	
NGL sales	86,763	86,519		86,763	86,739	
Oil sales	74,673	41,642		74,673	41,654	
Total	$ 415,394	$ 345,519	20%	$ 415,394	$ 345,707	20%
Third party transportation, gathering and compression fee components:						
Natural gas	$ 52,113	$ 32,441		$ 52,113	$ 32,458	
NGLs	3,168	2,135		3,168	2,135	
Total transportation, gathering and compression, as reported	$ 55,281	$ 34,576		$ 55,281	$ 34,593	
Production during the period (a):						
Natural gas (mcf)	60,280,617	45,147,273	34%	60,280,617	45,173,850	33%
NGLs (bbl)	1,992,028	1,553,546	28%	1,992,028	1,557,673	28%
Oil (bbl)	907,351	497,440	82%	907,351	497,585	82%
Gas equivalent (mcfe) (b)	77,676,891	57,453,189	35%	77,676,891	57,505,398	35%
Production – average per day (a):						
Natural gas (mcf)	655,224	490,731	34%	655,224	491,020	33%
NGLs (bbl)	21,652	16,886	28%	21,652	16,931	28%
Oil (bbl)	9,863	5,407	82%	9,863	5,409	82%
Gas equivalent (mcfe) (b)	844,314	624,491	35%	844,314	625,059	35%
Average prices, including cash-settled hedges and derivatives before third party transportation costs (c):						
Natural gas (mcf)	$ 4.21	$ 4.81	-12%	$ 4.21	$ 4.81	-12%
NGLs (bbl)	$ 43.56	$ 55.69	-22%	$ 43.56	$ 55.68	-22%
Oil (bbl)	$ 82.30	$ 83.71	-2%	$ 82.30	$ 83.71	-2%
Gas equivalent (mcfe) (b)	$ 5.35	$ 6.01	-11%	$ 5.35	$ 6.01	-11%
Average prices, including cash-settled hedges and derivatives (d):						
Natural gas (mcf)	$ 3.35	$ 4.10	-18%	$ 3.35	$ 4.09	-18%
NGLs (bbl)	$ 41.96	$ 54.32	-23%	$ 41.96	$ 54.31	-23%
Oil (bbl)	$ 82.30	$ 83.71	-2%	$ 82.30	$ 83.71	-2%
Gas equivalent (mcfe) (b)	$ 4.64	$ 5.41	-14%	$ 4.64	$ 5.41	-14%

(a) Represents volumes sold regardless of when produced.
(b) Oil and NGLs are converted to mcfe at a rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.
(c) Excluding third party transportation, gathering and compression costs.
(d) Net of transportation, gathering and compression costs.

RANGE RESOURCES CORPORATION

RECONCILIATION OF NATURAL GAS, NGLs AND OIL SALES AND DERIVATIVE FAIR VALUE INCOME (LOSS) TO CALCULATED CASH REALIZED NATURAL GAS, NGLs AND OIL PRICES WITH AND WITHOUT THIRD PARTY TRANSPORTATION, GATHERING AND COMPRESSION FEES
non-GAAP measures

(Unaudited, in thousands, except per unit data)	As Reported, GAAP Excludes Barnett Operations Twelve Months Ended December 31, 2012	2011	%	Non-GAAP Includes Barnett Operations Twelve Months Ended December 31, 2012	2011	%
Natural gas, NGLs and oil sales components:						
Natural gas sales	$ 612,354	$ 611,864		$ 612,354	$ 651,533	
NGLs sales	265,072	268,846		265,072	278,995	
Oil sales	237,963	168,961		237,963	169,722	
Cash-settled hedges (effective):						
Natural gas	238,259	123,595		238,259	132,201	
Crude oil	(1,954)	—		(1,954)	—	
Total natural gas, NGLs and oil sales, as reported	$ 1,351,694	$ 1,173,266	15%	$ 1,351,694	$ 1,232,451	10%
Derivative fair value income (loss) components:						
Cash-settled derivatives (ineffective):						
Natural gas	$ 4,477	$ 22,104		$ 4,477	$ 22,104	
NGLs	31,737	9,612		31,737	9,612	
Crude Oil	2,486	(9,574)		2,486	(9,574)	
Change in mark-to-market on unrealized derivatives	5,958	15,762		5,958	15,762	
Unrealized ineffectiveness	(3,221)	2,183		(3,221)	2,183	
Total derivative fair value income (loss), as reported	$ 41,437	$ 40,087		$ 41,437	$ 40,087	
Natural gas, NGLs and oil sales, including all cash-settled derivatives (c):						
Natural gas sales	$ 855,090	$ 757,563		$ 855,090	$ 805,838	
NGLs sales	296,809	278,458		296,809	288,607	
Oil sales	238,495	159,387		238,495	160,148	
Total	$ 1,390,394	$ 1,195,408	16%	$ 1,390,394	$ 1,254,593	11%
Third party transportation, gathering and compression fee components:						
Natural gas	$ 181,524	$ 114,289		$ 181,524	$ 119,546	
NGLs	10,921	6,466		10,921	6,466	
Total transportation, gathering and compression, as reported	$ 192,445	$ 120,755		$ 192,445	$ 126,012	
Production during the period (a):						
Natural gas (mcf)	216,554,689	145,206,124	49%	216,554,689	157,001,395	38%
NGLs (bbl)	6,967,114	5,352,181	30%	6,967,114	5,572,829	25%
Oil (bbl)	2,851,312	1,959,608	46%	2,851,312	1,967,881	45%
Gas equivalent (mcfe) (b)	275,465,245	189,076,858	46%	275,465,245	202,245,656	36%
Production – average per day (a):						
Natural gas (mcf)	591,679	397,825	49%	591,679	430,141	38%
NGLs (bbl)	19,036	14,664	30%	19,036	15,268	25%
Oil (bbl)	7,790	5,369	45%	7,790	5,391	44%
Gas equivalent (mcfe) (b)	752,637	518,019	45%	752,637	554,098	36%
Average prices, including cash-settled hedges and derivatives before third party transportation costs (c):						
Natural gas (mcf)	$ 3.95	$ 5.22	-24%	$ 3.95	$ 5.13	-23%
NGLs (bbl)	$ 42.60	$ 52.03	-18%	$ 42.60	$ 51.79	-18%
Oil (bbl)	$ 83.64	$ 81.34	3%	$ 83.64	$ 81.38	3%
Gas equivalent (mcfe) (b)	$ 5.05	$ 6.32	-20%	$ 5.05	$ 6.20	-19%
Average prices, including cash-settled hedges and derivatives (d):						
Natural gas (mcf)	$ 3.11	$ 4.43	-30%	$ 3.11	$ 4.37	-29%
NGLs (bbl)	$ 41.03	$ 50.82	-19%	$ 41.03	$ 50.63	-19%
Oil (bbl)	$ 83.64	$ 81.34	3%	$ 83.64	$ 81.38	3%
Gas equivalent (mcfe) (b)	$ 4.35	$ 5.68	-23%	$ 4.35	$ 5.58	-22%

(a) Represents volumes sold regardless of when produced.
(b) Oil and NGLs are converted to mcfe at a rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.
(c) Excluding third party transportation, gathering and compression costs.
(d) Net of transportation, gathering and compression costs.

RANGE RESOURCES CORPORATION

RECONCILIATION OF INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES AS REPORTED TO INCOME FROM OPERATIONS BEFORE INCOME TAXES EXCLUDING CERTAIN ITEMS, a non-GAAP measure
(Unaudited, in thousands, except per share data)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2012	2011	%	2012	2011	%
(Loss) income from continuing operations before income taxes, as reported	$ 82,926	$ (2,614)	3272%	$ 25,056	$ 78,263	-68%
Adjustment for certain items:						
Gain (loss) on sale of properties	(61,836)	(3,539)		(49,132)	(2,259)	
Barnett discontinued operations less gain on sale	—	(177)		—	18,827	
Change in mark-to-market on unrealized derivatives (gain) loss	24,117	51,331		(5,958)	(15,762)	
Unrealized derivative (gain) loss	(1,840)	348		3,221	(2,183)	
Abandonment and impairment of unproved properties	21,230	27,639		125,278	79,703	
Loss on early extinguishment of debt	11,063	—		11,063	18,576	
Prior year Pennsylvania impact fee	501	—		25,208	—	
Proved property and other asset impairment	34,273	—		35,554	38,681	
Lawsuit settlements	644	302		3,167	540	
Brokered natural gas and marketing – non cash stock-based compensation	452	348		1,765	1,455	
Direct operating – non-cash stock-based compensation	768	571		2,415	1,987	
Exploration expenses – non-cash stock-based compensation	1,001	940		4,049	4,108	
General & administrative – non-cash stock-based compensation	13,786	8,756		44,541	36,244	
Deferred compensation plan – non-cash adjustment	(14,352)	9,640		7,203	43,209	
Income from operations before income taxes, as adjusted	112,733	93,545	21%	233,430	301,389	-23%
Income tax expense, as adjusted						
Current	(1,778)	636		(1,778)	637	
Deferred	41,152	39,647		87,351	124,372	
Net income excluding certain items, a non-GAAP measure	$ 73,359	$ 53,262	38%	$ 147,857	$ 176,380	-16%
Non-GAAP income per common share						
Basic	$ 0.46	$ 0.34	35%	$ 0.93	$ 1.12	-17%
Diluted	$ 0.46	$ 0.33	39%	$ 0.92	$ 1.11	-17%
Non-GAAP diluted shares outstanding, if dilutive	160,559	160,051		160,307	159,441	

HEDGING POSITION AS OF FEBRUARY 26, 2013
(Unaudited)

	Daily Volume	Hedge Price
Gas (Mmbtu)		
1Q 2013 Swaps	205,000	$ 3.24
1Q 2013 Collars	280,000	$ 4.59 - $5.05
2Q 2013 Swaps	215,000	$ 3.28
2Q 2013 Collars	280,000	$ 4.59 - $5.05
3Q 2013 Swaps	220,000	$ 3.42
3Q 2013 Collars	280,000	$ 4.59 - $5.05
4Q 2013 Swaps	213,370	$ 3.62
4Q 2013 Collars	280,000	$ 4.59 - $5.05
2014 Collars	402,500	$ 3.81 - $4.47
2015 Collars	55,000	$ 4.03 - $4.50
Oil (Bbls)		
1Q 2013 Swaps	4,653	$ 96.52
1Q 2013 Collars	3,000	$90.60 - $100.00
2Q 2013 Swaps	4,825	$ 96.64
2Q 2013 Collars	3,000	$90.60 - $100.00
3Q 2013 Swaps	5,825	$ 96.74
3Q 2013 Collars	3,000	$90.60 - $100.00
4Q 2013 Swaps	6,825	$ 96.79
4Q 2013 Collars	3,000	$90.60 - $100.00
2014 Swaps	6,000	$ 94.54
2014 Collars	2,000	$85.55 - $100.00
2015 Swaps	2,000	$ 90.20
C5 Natural Gasoline (Bbls)		
1Q 2013 Swaps	6,500	$ 2.13
2Q 2013 Swaps	6,500	$ 2.13
3Q 2013 Swaps	6,500	$ 2.13
4Q 2013 Swaps	6,500	$ 2.13
C3 Propane (Bbls)		
1Q 2013 Swaps	5,344	$ 0.94
2Q 2013 Swaps	6,000	$ 0.93
3Q 2013 Swaps	6,000	$ 0.93
4Q 2013 Swaps	6,000	$ 0.93

NOTE: SEE WEBSITE FOR OTHER SUPPLEMENTAL INFORMATION FOR THE PERIODS