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 26, 2014 (February 25, 2014)

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 25, 2014 Range Resources Corporation issued a press release announcing its 2013 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 25, 2014

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 26, 2014

EXHIBIT INDEX

Exhibit Number	**Description**
99.1	Press Release dated February 25, 2014

RANGE REPORTS OUTSTANDING 2013 RESULTS

FORT WORTH, TEXAS, FEBRUARY 25, 2014…RANGE RESOURCES CORPORATION (NYSE: RRC) today announced its 2013 financial results.

2013 Highlights –

- Record annual average daily production of 940 Mmcfe per day, an increase of 25% over 2012
- Adjusted cash flow was $943 million, an increase of 25% over 2012
- Unit costs reduced by $0.33 per mcfe versus 2012
- Total proved reserves increased by 26% to 8.2 Tcfe
- Reserve replacement of 612% at $0.61 per mcfe all-in finding and development cost
- Unrisked resource potential increases to 64—85 Tcfe
- Net income for 2013 was $116 million versus $13 million in 2012
- Increased projected EURs in southwest Marcellus for 2014 and 2015 drilling programs

Production for 2013 averaged 940 Mmcfe per day, a 25% increase over 2012. Fourth quarter 2013 production increased 20% over the prior-year period to 1,012 Mmcfe per day, another record high for Range and was 5% higher than third quarter 2013. Oil and natural gas liquid (“NGL”) production increased 35% over the prior year fourth quarter.

Proved reserves increased 26% year-over-year to 8.2 Tcfe, driven by a 38% increase in proved developed producing reserves. All-in finding and development cost averaged $0.61 per mcfe, while replacing 612% of production from drilling. Drill bit finding cost averaged $0.57 per mcfe. Production and reserves per share on a debt-adjusted basis increased 26% and 25%, respectively. This represents the eighth consecutive year of double-digit per-share growth for both production and reserves. Range’s unrisked unproved resource potential at year-end 2013 increased to 64—85 Tcfe; including 3.7 – 4.9 billion barrels of NGLs and crude oil.

Commenting, Jeff Ventura, the Company’s President and CEO, said, “2013 was an outstanding year for Range as per share debt-adjusted reserves and production both grew at 25% or more. Our reserves grew 26% to 8.2 Tcfe, replacing 612% of our production. This was done at an all-in finding and development cost of just $0.61 per mcfe. Over the past four years, we have successfully moved 6.4 Tcfe of unproved resource potential into proved reserves. This excellent performance has driven our DD&A rate down to $1.36 per mcfe in the fourth quarter, a 47% decrease from four years ago. Over the same time period, our direct operating expense per mcfe decreased 53% to $0.36 per mcfe as we focused capital towards the Marcellus. Net income for 2013 increased to $116 million from $13 million in 2012. In short, Range has seen great improvements in capital efficiencies and the results are flowing through to the bottom line.

Going forward, Range has three critical components we believe will differentiate us. First, Range has a sizeable position in the core of perhaps the best gas play in North America that will fuel our growth and allow us to continue driving capital efficiency improvements. Second, we have a team with a proven track record that consistently executes well. Lastly, Range has put in place innovative marketing and transportation arrangements that demonstrate the capabilities of our strong and forward thinking marketing team. These factors allow us to confidently say we plan to grow production by 20% to 25% for many years. By combining continual capital efficiency improvements with expected production doubling every three to four years, we believe we can drive substantial per share value for our shareholders for years to come.”

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. "Unit costs" as used in this release are composed of direct operating, transportation, gathering and compression, production and ad valorem tax, general and administrative, interest and depletion, depreciation and amortization costs divided by production. See "Non-GAAP Financial Measures" for a definition of each of the non-GAAP financial measures and the tables that reconcile each of the non-GAAP measures to their most directly comparable GAAP financial measure.)

Full Year 2013

GAAP revenues for 2013 totaled $1.9 billion (28% increase compared to 2012), GAAP net cash provided from operating activities including changes in working capital reached $744 million (15% increase compared to 2012) and GAAP earnings were $116 million ($0.70 per diluted share) versus $13 million ($0.08 per diluted share) in 2012.

Non-GAAP revenues for 2013 totaled $1.7 billion (24% increase compared to 2012), cash flow from operations before changes in working capital, a non-GAAP measure, reached $943 million (25% increase compared to 2012). Adjusted net income, a non-GAAP measure, was $234 million ($1.45 per diluted share, a 58% increase over 2012). Wellhead prices, after adjustment for all cash-settled hedges and derivatives, averaged $4.91 per mcfe. The Company's cost structure continued to improve as total unit costs decreased by $0.33 per mcfe or 8% as compared to the prior year. Interest expense decreased 16% to $0.51 per mcfe and depreciation, depletion and amortization expense decreased 11% to $1.44 per mcfe.

The Company announced its full year 2013 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which would correspond to analysts' estimates) averaged $4.91 per mcfe, a 3% composite decrease from the prior year.

- Production and realized prices by each commodity for 2013 were: natural gas – 725 Mmcf per day ($4.00 per mcf), NGLs – 25,356 barrels per day ($32.71 per barrel) and crude oil and condensate – 10,486 barrels per day ($84.70 per barrel).
- The 2013 average natural gas pricing improved $0.78 per mcf, before hedging settlements, as compared to the prior year. Financial hedges added $0.39 per mcf in 2013 and added $1.12 per mcf in the prior year. The average Company natural gas differential for the year was $(0.06) per mcf.
- NGL pricing, before hedges, was 35% of the West Texas Intermediate index ("WTI") for 2013 compared to 41% of WTI in 2012. The change was primarily due to a disproportionate increase in WTI price compared to the NGL pricing components during 2013.
- Crude oil and condensate price realizations, before hedges, for the year averaged 88% of WTI compared to 89% in 2012.

Fourth Quarter

GAAP revenues for the fourth quarter of 2013 totaled $428 million (7% decrease as compared to fourth quarter 2012), GAAP net cash provided from operating activities including changes in working capital reached $241 million (a 29% increase as compared to fourth quarter 2012) and GAAP earnings were $28 million ($0.17 per diluted share) versus earnings of $53 million ($0.32 per diluted share) in the prior year quarter. 2013 results included $59 million in derivative losses due to increased commodity prices and a $22 million deferred compensation plan expense due to increases in the Company's stock price, while 2012 included a $62 million gain on the sale of assets.

Non-GAAP revenues for fourth quarter 2013 totaled $461 million (10% increase compared to fourth quarter 2012), cash flow from operations before changes in working capital, a non-GAAP measure, reached $252 million. Adjusted net income, a non-GAAP measure, was $68 million ($0.42 per diluted share for the fourth quarter 2013). Wellhead prices, after adjustment for all cash-settled hedges and derivatives, averaged $4.79 per mcfe. The Company's total unit costs decreased by $0.19 per mcfe or 5% compared to the prior-year quarter. Interest expense for the quarter was $0.48 per mcfe, a 17% decrease compared to the prior year quarter. Depreciation, depletion and amortization expense decreased 7% to $1.36 per mcfe.

The Company also announced its fourth quarter 2013 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which would correspond to analysts' estimates) averaged $4.79 per mcfe, a 10% composite decrease from the prior year quarter.

- Production and realized prices by each commodity for the fourth quarter of 2013 were: natural gas – 756 Mmcf per day ($3.84 per mcf), NGLs – 31,386 barrels per day ($32.20 per barrel) and crude oil and condensate – 11,221 barrels per day ($82.94 per barrel).
- The fourth quarter average natural gas price decreased $0.14 per mcf, before hedging settlements, as compared to the prior year quarter. Financial hedges added $0.44 per mcf in the current quarter and added $0.67 per mcf in the prior year quarter. The average Company natural gas differential for the fourth quarter was largely maintained at $(0.22) per mcf as compared to the third quarter of $(0.17) per mcf.
- NGL pricing, before hedges, was 37% of WTI for the fourth quarter compared to 43% of WTI in the prior year quarter. The change was primarily due to a disproportionate increase in WTI price compared to the NGL components pricing during 2013. NGL realizations for the fourth quarter improved compared to third quarter 2013 pricing of 31% of WTI. The change was primarily due to an increase in propane prices during the quarter. Marcellus ethane contributed 5,450 barrels per day to the NGL mix during the fourth quarter.
- Crude oil and condensate price realizations, before hedges, for the fourth quarter averaged 86% of WTI compared to 89% in the prior year quarter. Crude oil and condensate realizations for third quarter 2013 were 87% of WTI before hedges.

Balance Sheet

During 2013, Range strengthened its balance sheet with the sale of its New Mexico properties and other miscellaneous properties for approximately $316 million. The sale proceeds were used to reduce the outstanding balance on its bank credit facility. At year-end 2013, the Company had $1.2 billion of committed liquidity on its credit facility.

Capital Expenditures

Fourth quarter drilling expenditures of $228 million funded the drilling of 43 (42 net) wells. Drilling expenditures for 2013 totaled $1.1 billion, and Range drilled 219 (209 net) wells and 2 (1.6 net) recompletions during the year. A 100% success rate was achieved. In addition, during the year, $138 million was spent on acreage purchases, $47 million on gas gathering systems and $60 million on exploration expense. All-in finding and development cost for 2013 averaged $0.61 per mcfe with reserve replacement of 612%. Drill bit only finding cost averaged $0.57 per mcfe.

Range has set its 2014 capital spending budget at $1.52 billion. The capital budget includes approximately $1.19 billion for drilling and recompletions, $210 million for leasehold and renewals, $85 million for pipelines and facilities and $35 million for seismic. Approximately 87% of the budget will be targeted towards the Marcellus. Range projects that the 2014 capital budget will generate 20% – 25% year-over-year production growth.

Included in its 2014 capital budget, Range has elected to increase the lateral lengths and the number of frac stages for its 2014 Marcellus wells in the southwestern portion of the play from its previously announced plans in July of last year. Generally, lateral lengths will range from 4,200 to 5,300 feet with the number of frac stages proportionately increased from 23 to 25 for 2014. This is an overall increase of over 10% compared to its previously announced program. Accordingly, the expected EURs, rates of return and costs have been increased and are included in the Company’s updated presentation on its website.

Operational Discussion

Range has updated its investor presentation with updated economic sensitivity analysis for the Marcellus. Please see www.rangeresources.com under the Investor Relations tab, “Presentations and Webcasts” area, for the presentation entitled, “Company Presentation – February 25, 2014”

***Marcellus Shale Marketing and Transportation Update** -*

Range realized many years ago that Marcellus growth would exceed demand in the Northeast except during the peak demand in the winter. As a result, Range has focused its marketing efforts on developing new and sometimes non-traditional markets outside of the Appalachian basin, along with securing transportation arrangements to serve these markets. In 2013, the Company continued to make progress on this marketing strategy by adding 25 new natural gas customers in the South, Southeast, Mid-Atlantic and Midwest markets. Subsequently, the Company secured the firm transportation or firm sales arrangements to enable gas delivery. Range has tied the sales price of its natural gas to nine different indices, creating a diversified portfolio for the Company. Due to Range's significant growth plans, the Company has secured approximately 1.1 Bcf per day of firm capacity increasing to 1.6 Bcf per day by 2016. Recently, Range has contracted for 197,500 dth per day of capacity on Texas Eastern. This capacity is expected to be in service by November 1, 2015 and will move gas westward to the Lebanon Lateral in western Ohio to other pipeline interconnections and Midwest customers through firm sales arrangements. During November, Range acquired another 150,000 dth per day on the Spectra Energy Gulf Market Expansion Project expected to be in service in 2016. This service moves gas from the Marcellus to the industrial and LNG export sectors along the Gulf Coast. By 2017, Range anticipates having the capability of selling Appalachian gas to customers as far west as Wisconsin, on a line south to Texas, east to Florida and north to Maine; an area comprising two-thirds of domestic natural gas consumption.

Range, being the largest producer of wet gas in the Appalachian Basin, has taken a similar diversified approach to marketing its growing volumes of NGLs. The Company's most innovative marketing solutions have targeted ethane and propane, which is expected to account for over two thirds of Range's NGL barrel in 2014. Regarding ethane, Range has three marketing arrangements that not only ensure that natural gas pipeline specifications are met now and for the foreseeable future, but also lock in impressive project economics. If all three marketing arrangements were fully operational today, Range's ethane revenue would increase by over 25% compared to leaving the ethane in the gas stream (net of all transportation and processing costs and including additional propane recovery). For Range, ethane extraction and sale enhance cash flow and earnings. In December, two of the three projects became operational for Range as Mariner West began supplying ethane to Sarnia, Ontario, Canada and the ATEX project started line fill. The third project, Mariner East, is expected to further diversify and strengthen Range's NGL marketing abilities when it becomes operational in 2015 by selling ethane to INEOS for use in their European petrochemical facilities. Range currently has the ability to export propane to Central America, South America and Europe utilizing the Marcus Hook facility in Philadelphia. Range is geographically advantaged to supply propane to strong northeast markets during winter heating season and also export to high-demand international markets during the summer.

***Marcellus Shale** -*

Production for the fourth quarter averaged approximately 968 (813 net) Mmcfe per day for the Marcellus Shale division. Production for 2013 averaged approximately 883 (742 net) Mmcfe per day, which represents a 37% increase over the prior year. The division's fourth quarter net production included 611 Mmcf per day of gas, 25,700 barrels per day of NGLs and 7,900 barrels per day of condensate. Range sold on average 5,450 net barrels of ethane per day during the quarter.

***Southern Marcellus Shale Division** -*

During the fourth quarter, the division brought online 28 Marcellus wells in southwest Pennsylvania, 27 of which were located in the liquids-rich area of the play. The initial 24-hour production rates of the liquids-rich wells averaged 2,276 (1,799 net) boe per day with 63% liquids assuming 80% ethane extraction.

In the super-rich area of southwest Pennsylvania the division brought online 15 (14.6 net) wells in the fourth quarter. The initial 24-hour production rates of these super-rich wells averaged 2,160 (1,738 net) boe per day with 67% liquids assuming 80% ethane extraction. The average lateral length for the wells was 3,894 feet and they averaged 20 frac stages per lateral. The results are further confirmation that improved targeting and completion techniques are increasing expected recoveries across the play. After combining these wells with performance history from similar wells drilled in the area, Range raised its 2014 super-rich type curve to 2.05 Mmboe, with an average lateral length of 5,300 feet completed with an average of 26 stages. Range also announced today expectations for its 2015 super-rich well designs using an average lateral length of 5,600 feet and 28 frac stages. The associated EUR for the projected 2015 super-rich drilling program is 2.23 Mmboe.

In the wet area of southwest Pennsylvania the division brought online 12 (11.3 net) wells in the fourth quarter. The initial 24-hour production rates of these wells averaged 14.5 (11.2 net) Mmcfe per day with 59% liquids assuming 80% ethane extraction. The average lateral length for the wells was 3,909 feet and they averaged 20 frac stages per lateral. In 2014, Range plans to drill wells in the wet area that will average approximately 4,200 feet in lateral length with 21 stages. As a result of increased stages and longer laterals, the Company expects its 2014 wet Marcellus type curve to be 12.3 Bcfe. Range announced today expectations for its 2015 wet Marcellus well designs using an average lateral length of 4,800 feet and 24 frac stages. The associated EUR for the projected 2015 wet Marcellus drilling program is 14 Bcfe.

In the dry area of southwest Pennsylvania, Range plans to drill wells this year and in 2015 that will average approximately 5,200 feet in lateral length with 26 stages. As a result of increased stages and longer laterals, the Company increased its dry Marcellus type curve to 13.4 Bcf.

In 2014, the Company also plans to drill a Utica/Point Pleasant well underneath its Marcellus position in Washington County, Pennsylvania. Based on the Company's gas in place (GIP) maps, released in October, the highest GIP in the Utica/Point Pleasant shale is directly beneath the Company's acreage in southwest Pennsylvania. Based on existing well control, Range expects excellent reservoir quality in the Point Pleasant. Industry activity to the west of the Company's acreage indicates there is significant potential for high-rate dry gas wells in the area. Range has 400,000 acres in southwest Pennsylvania that are prospective for Utica/Point Pleasant, based on GIP analysis, delineation from offset activity and other geological data.

Northern Marcellus Shale Division -

The northern Marcellus division continues to maintain Range's acreage position with one drilling rig. During the fourth quarter, the division turned ten (10.0 net) wells to sales. A significant well was drilled in Lycoming County that produced at a 24-hour rate of 26.0 (21.9 net) Mmcf per day from a lateral of 2,903 feet and 10 frac stages. The previously announced four well step-out pad in Lycoming County continues to perform well. The wells have an average lateral length of 5,047 feet and 22 frac stages. In the first 90 days the three most recent wells have combined to produce over 4.0 Bcf of gas. One of those wells had a lateral length of 6,353 feet with 32 stages, averaged over 22 Mmcf per day over the first 30 days and has a projected EUR of 18 Bcf. We have a 100% WI and a NRI of 86% in that well. Range is currently running one rig in northeast Pennsylvania and anticipates running one or two rigs for 2014 to maintain continuous drilling commitments under the leases. In 2014, the Company expects to turn 14 wells to sales in northern Marcellus. Drilling activity during the year will incorporate average lateral lengths of 4,600 feet and 23 frac stages.

Midcontinent Division -

During the fourth quarter, Range continued to test and evaluate new completions using larger frac stimulations on its Mississippian Chat acreage along the Nemaha Ridge. Six wells were turned to sales in 2013 utilizing the larger frac design with an average lateral length of 3,519 feet and 17 frac stages. The average 60-day production rate for all six wells was 475 (364 net) boe per day with 73% liquids. In 2014, the Company expects to continue monitoring well performance on larger frac completions while further delineating its 160,000 net acre position by drilling 14 wells in the Mississippian Chat.

A one rig program is anticipated in the Texas Panhandle for most of 2014 where Range has had success drilling Horizontal St. Louis wells. Another St. Louis well was turned to sales in the fourth quarter with an initial 24-hour production rate of 11.8 (5.5 net) Mmcfe per day. Seven to eight additional St. Louis wells are planned for sales in 2014. For the year, the Midcontinent division produced an average of 87 Mmcfe per day during 2013.

Permian Division -

Range’s Permian division is targeting the Wolfcamp and Cline Shale oil plays in West Texas. During the fourth quarter, Range turned to sales an Upper Wolfcamp well with an initial 24-hour production rate of 1,197 (898 net) boe per day with 58% oil and 79% liquids from a 6,406 foot lateral with 26 frac stages. Range has also turned to sales a Cline well that had an initial production rate of 989 (742 net) boe per day with 60% oil and 85% liquids from a 6,582 foot lateral with 27 frac stages. In 2013, the division produced an average of 39 Mmcfe per day.

Southern Appalachia Division -

The Southern Appalachia division continued development of the multi-pay horizons on its 230,000 net acre position in Virginia during the fourth quarter of 2013. Range owns the fee minerals on 216,000 net acres of this position and receives the added economic benefit of the royalty for wells drilled on this acreage. The division continues to optimize its completions in the traditional tight gas sands, horizontal Huron and coal bed methane horizons while holding its division’s production to a minimal decline with its reduced capital allocation. The division’s Nora property is strategically located along the mid-Atlantic pipelines giving it access to premium markets in the southeast and the highest natural gas prices in Appalachia. In total, 19 wells were turned to sales during the year as the division produced an average of 73 Mmcfe per day

Guidance – First Quarter 2014

Production per day Guidance:

Production growth for 2014 is targeted at 20%-25% year-over-year. Production for the first quarter of 2014 is expected to be 1.05 Bcfe per day. Liquids are expected to be approximately 30%—35% of first quarter production.

Guidance for 2014 Activity:

Under the current plan, Range expects to turn to sales approximately 163 net wells in the Marcellus and Midcontinent during 2014, as shown below.

	Total Planned Wells to Sales in 2014
Super-Rich area	62
Wet area	53
Dry area (NE & SW)	26
Total Marcellus	141
Midcontinent	22
Total	**163**

1Q 2014 Expense Guidance:

Direct operating expense:	\$0.37 - \$0.39 per mcfe
Transportation, gathering and compression expense:	\$0.74 - \$0.76 per mcfe
Production tax expense:	\$0.14 - \$0.15 per mcfe
Exploration expense:	\$17 - \$19 million
Unproved property impairment expense:	\$12 - \$14 million
G&A expense:	\$0.39 - \$0.41 per mcfe
Interest expense:	\$0.47 - \$0.49 per mcfe
DD&A expense:	\$1.36 - \$1.39 per mcfe

Differential Pricing History (a)

	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013
Natural Gas	($ 0.03)	$ 0.18	$ 0.15	$ 0.04	($ 0.17)	($ 0.22)
NGL (% of WTI NYMEX)	33%	43%	38%	33%	31%	37%
Oil (% of WTI NYMEX)	90%	89%	90%	89%	87%	86%

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

Hedging Status

Range hedges portions of its expected future production volumes to increase the predictability of cash flow and to help maintain a strong, flexible financial position. Range currently has over 80% of its expected 2014 natural gas production hedged at a weighted average floor price of $3.96 per mcf and a weighted average ceiling price of $4.38. Similarly, Range has hedged more than 80% of its 2014 projected crude oil production at a floor price of $92.82 and approximately half of its composite NGL production. Please see Range's detailed hedging schedule posted at the end of the financial tables below and on its website at www.rangeresources.com.

Effective March 1, 2013, Range elected to discontinue hedge accounting for derivative contracts and moved to mark-to-market accounting for its derivative contracts. The mark-to-market accounting treatment may create fluctuations in earnings as commodity prices change both positively and negatively, however, such mark-to-market adjustments have no cash flow impact. The impact to cash flow will occur as the underlying contracts are settled. As of December 31, 2013, the Company expects to reclassify into earnings in 2014, $10.2 million of unrealized net gains frozen in accumulated other comprehensive income due to the discontinuance of hedge accounting.

Conference Call Information

A conference call to review the financial results is scheduled on Wednesday, February 26 at 9:00 a.m. ET. To participate in the call, please dial 877-407-0778 and ask for the Range Resources 2013 financial results conference call. A replay of the call will be available through March 30. To access the phone replay dial 877-660-6853. The conference ID is 13574766.

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 30.

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 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 estimated and unaudited costs incurred excluding asset retirement obligations and divided by proved reserve additions (extensions, discoveries and additions shown in the table) adjusted for the changes in proved reserves for acreage, acquisitions, performance revisions and/or price revisions as stated in each instance in the release. Drill bit development cost per mcfe is based on estimated and unaudited drilling, development and exploration costs incurred divided by the total of reserve additions and performance revisions. These calculations do 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, 2013 may be reconciled to its standardized measure of discounted future net cash flows as of December 31, 2013 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, 2013
Standardized measure of discounted future net of cash flows	$ 5,862
Discounted future cash flows for income taxes	2,036
Discounted future net cash flows before income taxes (PV-10)	$ 7,898

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 open derivative positions. 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/.

All statements, except for statements of historical fact, made in this release regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future liquidity, production growth, completion of ethane projects, resolution of pipeline quality requirements, estimated gas in place, future rates of return, future low costs, low reinvestment risk, earnings and per-share value, capital spending plans, firm capacity contract renewals, future transportation capacity rates, continued utilization of existing infrastructure, gas marketability, firm sales contract renewals, maximized realized natural gas prices, acreage quality, access to multiple gas markets, expected drilling and development plans, improved capital efficiency, future financial position and future guidance information 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 actual 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, environmental risks and regulatory changes. 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" or "upside" 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 actually being 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 resource potential has not been fully risked by Range's management. "EUR," or estimated ultimate recovery, refers to our management's estimates of hydrocarbon quantities that may be recovered from a well completed as a producer in the area. These quantities may 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. Actual quantities that may be recovered from Range's interests could 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.

2014-04

SOURCE: Range Resources Corporation

Investor Contacts:

Rodney Waller, Senior Vice President
817-869-4258

David Amend, Investor Relations Manager
817-869-4266

Laith Sando, Research Manager
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

RANGE RESOURCES CORPORATION

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,		
	2013	2012	%	2013	2012	%
Revenues and other income:						
Natural gas, NGLs and oil sales (a)	$448,545	$398,688		$1,715,676	$1,351,694	
Derivative fair value (loss) income	(59,355)	(5,571)		(61,825)	41,437	
Gain (loss) on sale of assets	3,162	61,836		92,291	49,132	
Brokered natural gas, marketing and other (c)	14,809	2,948		55,546	15,078	
Brokered natural gas – blending (c)	22,535	—		62,751	—	
Equity method investment (c)	(79)	(177)		462	(372)	
ARO settlement loss (c)	(1,924)	—		(2,938)	—	
Other (c)	393	314		756	735	
Total revenues and other income	428,086	458,038	-7%	1,862,719	1,457,704	28%
Costs and expenses:						
Direct operating	33,661	29,446		125,336	113,490	
Direct operating – non-cash stock-based compensation (b)	699	768		2,755	2,415	
Transportation, gathering and compression	66,820	55,281		256,242	192,445	
Production and ad valorem taxes	11,290	9,380		45,240	41,912	
Pennsylvania impact fee—prior year	—	501		—	25,208	
Brokered natural gas and marketing	15,344	4,542		60,113	18,669	
Brokered natural gas and marketing – non-cash stock-based compensation (b)	542	452		1,852	1,765	
Brokered natural gas and marketing – blending	25,806	—		69,821	—	
Exploration	13,053	17,021		60,384	65,758	
Exploration – non-cash stock-based compensation (b)	1,012	1,001		4,025	4,049	
Abandonment and impairment of unproved properties	5,852	21,230		51,918	125,278	
General and administrative	38,740	31,402		143,265	125,355	
General and administrative – non-cash stock-based compensation (b)	21,137	13,786		55,737	44,541	
General and administrative – lawsuit settlements	330	644		91,919	3,167	
General and administrative – bad debt expense	—	750		250	750	
Deferred compensation plan (d)	22,039	(14,352)		55,296	7,203	
Interest expense	44,955	44,708		176,557	168,798	
Loss on early extinguishment of debt	—	11,063		12,280	11,063	
Depletion, depreciation and amortization	126,958	113,216		492,397	445,228	
Impairment of proved properties and other assets	—	34,273		7,753	35,554	
Total costs and expenses	428,238	375,112	14%	1,713,140	1,432,648	20%
Income (loss) from continuing operations before income taxes	(152)	82,926	-100%	149,579	25,056	497%
Income tax expense (benefit):						
Current	(143)	(1,778)		(143)	(1,778)	
Deferred	(28,180)	31,742		34,000	13,832	
	(28,323)	29,964		33,857	12,054	
Net income (loss)	$ 28,171	$ 52,962	-47%	$ 115,722	$ 13,002	790%
Net Income (Loss) Per Common Share:						
Basic	$ 0.17	$ 0.33		$ 0.71	$ 0.08	
Diluted	$ 0.17	$ 0.32		$ 0.70	$ 0.08	
Weighted average common shares outstanding, as reported:						
Basic	160,555	159,832	0%	160,438	159,431	1%
Diluted	161,496	160,559	1%	161,407	160,307	1%

(a) See separate natural gas, NGLs and oil sales information table.
(b) 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.
(c) Included in Brokered natural gas, marketing and other revenues in the 10-K.
(d) Reflects the change in market value of the vested Company stock held in the deferred compensation plan.

RANGE RESOURCES CORPORATION

BALANCE SHEETS
(In thousands)

	December 31, 2013 (Audited)	December 31, 2012 (Audited)
Assets		
Current assets	$ 192,466	$ 190,062
Derivative assets	4,421	137,552
Deferred tax assets	51,414	—
Natural gas and oil properties, successful efforts method	6,758,437	6,096,184
Transportation and field assets	32,784	41,567
Other	259,564	263,370
	$7,299,086	$6,728,735
Liabilities and Stockholders' Equity		
Current liabilities	$ 464,326	$ 448,202
Asset retirement obligations	5,037	2,470
Derivative liabilities	26,198	4,471
Bank debt	500,000	739,000
Subordinated notes	2,640,516	2,139,185
	3,140,516	2,878,185
Deferred tax liability	771,980	698,302
Derivative liabilities	25	3,463
Deferred compensation liability	247,537	187,604
Asset retirement obligations and other liabilities	229,015	148,646
	1,248,557	1,038,015
Common stock and retained earnings	2,411,853	2,278,243
Common stock held in treasury stock	(3,637)	(4,760)
	2,408,216	2,273,483
Accumulated other comprehensive income	6,236	83,909
Total stockholders' equity	2,414,452	2,357,392
	$7,299,086	$6,728,735

RECONCILIATION OF TOTAL REVENUES AND OTHER INCOME TO TOTAL REVENUE EXCLUDING CERTAIN ITEMS, a non-GAAP measure
(Unaudited, in thousands)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2013	2012	%	2013	2012	%
Total revenues and other income, as reported	$428,086	$458,038	-7%	$1,862,719	$1,457,704	28%
Adjustment for certain special items:						
Total change in fair value related to derivatives prior to settlement (gain) loss	56,434	22,277		30,569	(2,737)	
ARO settlement loss	1,924	—		2,938	—	
(Gain) loss on sale of assets	(3,162)	(61,836)		(92,291)	(49,132)	
Brokered natural gas—blending	(22,535)	—		(62,751)	—	
Total revenues, as adjusted, non-GAAP	$460,747	$418,479	10%	$1,741,184	$1,405,835	24%

RANGE RESOURCES CORPORATION

CASH FLOWS FROM OPERATING ACTIVITIES

(Unaudited, in thousands)

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Twelve Months Ended December 31, 2013	Twelve Months Ended December 31, 2012
Net income (loss)	$ 28,171	$ 52,962	$115,722	$ 13,002
Adjustments to reconcile net cash provided from continuing operations:				
(Gain) Loss from equity method investment, net of distributions	(1,799)	3,418	(2,973)	5,670
Deferred income tax expense (benefit)	(28,180)	31,742	34,000	13,832
Depletion, depreciation, amortization and impairment	126,958	147,489	500,150	480,782
Exploration dry hole costs	1,795	9	5,699	841
Abandonment and impairment of unproved properties	5,852	21,230	51,918	125,278
Derivative fair value loss (income)	59,355	5,571	61,825	(41,437)
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	(2,921)	16,706	(31,256)	38,700
Allowance for bad debts	—	750	250	750
Amortization of deferred issuance costs, loss on extinguishment of debt and other	4,131	17,195	23,866	23,165
Deferred and stock-based compensation	45,211	1,563	119,398	60,136
Gain (loss) on sale of assets and other	(3,162)	(61,836)	(92,291)	(49,132)
Changes in working capital:				
Accounts receivable	(14,706)	(28,538)	(21,212)	(38,017)
Inventory and other	526	(1,982)	3,785	(7,376)
Accounts payable	15,679	2,580	(13,555)	13,654
Accrued liabilities and other	3,762	(22,884)	(11,788)	7,251
Net changes in working capital	5,261	(50,824)	(42,770)	(24,488)
Net cash provided from operating activities	$240,672	$185,975	$743,538	$647,099

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, 2013	Three Months Ended December 31, 2012	Twelve Months Ended December 31, 2013	Twelve Months Ended December 31, 2012
Net cash provided from operating activities, as reported	$240,672	$185,975	$743,538	$647,099
Net changes in working capital	(5,261)	50,824	42,770	24,488
Exploration expense	11,258	12,873	54,685	60,778
Lawsuit settlements	330	644	91,919	3,167
Equity method investment distribution / intercompany elimination	1,877	(3,241)	2,509	(5,298)
Loss on gas blending	3,271	—	7,070	—
Prior year Pennsylvania impact fee	—	501	—	25,208
Non-cash compensation adjustment	331	293	767	295
Cash flow from operations before changes in working capital—a non-GAAP measure	$252,478	$247,869	$943,258	$755,737

ADJUSTED WEIGHTED AVERAGE SHARES OUTSTANDING

(Unaudited, in thousands)

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Twelve Months Ended December 31, 2013	Twelve Months Ended December 31, 2012
Basic:				
Weighted average shares outstanding	163,425	162,627	163,223	162,306
Stock held by deferred compensation plan	(2,870)	(2,795)	(2,785)	(2,875)
Adjusted basic	160,555	159,832	160,438	159,431
Dilutive:				
Weighted average shares outstanding	163,425	162,627	163,223	162,306
Dilutive stock options under treasury method	(1,929)	(2,068)	(1,816)	(1,999)
Adjusted dilutive	161,496	160,559	161,407	160,307

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)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2013	2012	%	2013	2012	%
Natural gas, NGL and Oil Sales components:						
Natural Gas Sales	$ 236,497	$ 213,348		$ 954,673	$ 612,354	
NGL Sales	103,797	75,468		315,272	265,072	
Oil Sales	86,125	71,245		329,182	237,963	
Cash-settled hedges (effective):						
Natural Gas	20,255	39,584		110,948	238,259	
Crude Oil	1,871	(957)		5,601	(1,954)	
Total Oil and Gas Sales, as reported	$ 448,545	$ 398,688	13%	$ 1,715,676	$ 1,351,694	27%
Derivative Fair Value Income (Loss), as reported	$ (59,355)	$ (5,571)		$ (61,825)	$ 41,437	
Cash settlements on derivative financial instruments – (gain) loss:						
Natural Gas	(10,268)	(1,026)		8,090	(4,477)	
NGLs	10,807	(11,295)		12,566	(31,737)	
Crude Oil	2,382	(4,385)		10,600	(2,486)	
Total change in fair value related to derivatives prior to settlement, a non-GAAP measure	$ (56,434)	$ (22,277)		$ (30,569)	$ 2,737	
Transportation, Gathering and Compression components:						
Natural Gas	$ 63,556	$ 52,113		$ 243,127	$ 181,524	
NGLs	3,264	3,168		13,115	10,921	
Total transportation, gathering and compression, as reported	$ 66,820	$ 55,281		$ 256,242	$ 192,445	
Natural gas, NGL and Oil sales, including cash-settled derivatives (c):						
Natural Gas Sales	$ 267,020	$ 253,958		$ 1,057,531	$ 855,090	
NGL Sales	92,990	86,763		302,706	296,809	
Oil Sales	85,614	74,673		324,183	238,495	
Total	$ 445,624	$ 415,394	7%	$ 1,684,420	$ 1,390,394	21%
Production of Oil and Gas during the periods (a):						
Natural Gas (mcf)	69,553,207	60,280,617	15%	264,528,254	216,554,689	22%
NGL (bbl)	2,887,548	1,992,028	45%	9,254,801	6,967,114	33%
Oil (bbl)	1,032,299	907,351	14%	3,827,491	2,851,312	34%
Gas equivalent (mcfe) (b)	93,072,289	77,676,891	20%	343,022,006	275,465,245	25%
Production of Oil and Gas – average per day (a):						
Natural Gas (mcf)	756,013	655,224	15%	724,735	591,679	22%
NGL (bbl)	31,386	21,652	45%	25,356	19,036	33%
Oil (bbl)	11,221	9,863	14%	10,486	7,790	35%
Gas equivalent (mcfe) (b)	1,011,655	844,314	20%	939,786	752,637	25%
Average prices, including cash settled hedges that qualify for hedge accounting before third party transportation costs:						
Natural Gas (per mcf)	$ 3.69	$ 4.20	-12%	$ 4.03	$ 3.93	3%
NGL (per bbl)	$ 35.95	$ 37.89	-5%	$ 34.07	$ 38.05	-10%
Oil (per bbl)	$ 85.24	$ 77.47	10%	$ 87.47	$ 82.77	6%
Gas equivalent (per mcfe) (b)	$ 4.82	$ 5.13	-6%	$ 5.00	$ 4.91	2%
Average prices, including cash-settled hedges and derivatives before third party transportation costs (c):						
Natural Gas (per mcf)	$ 3.84	$ 4.21	-9%	$ 4.00	$ 3.95	1%
NGL (per bbl)	$ 32.20	$ 43.56	-26%	$ 32.71	$ 42.60	-23%
Oil (per bbl)	$ 82.94	$ 82.30	1%	$ 84.70	$ 83.64	1%
Gas equivalent (per mcfe) (b)	$ 4.79	$ 5.35	-10%	$ 4.91	$ 5.05	-3%
Average prices, including cash-settled hedges and derivatives (d):						
Natural Gas (per mcf)	$ 2.93	$ 3.35	-13%	$ 3.08	$ 3.11	-1%
NGL (per bbl)	$ 31.07	$ 41.96	-26%	$ 31.29	$ 41.03	-24%
Oil (per bbl)	$ 82.94	$ 82.30	1%	$ 84.70	$ 83.64	1%
Gas equivalent (per mcfe) (b)	$ 4.07	$ 4.64	-12%	$ 4.16	$ 4.35	-4%
Transportation, gathering and compression expense per mcfe	$ 0.72	$ 0.71	1%	$ 0.75	$ 0.70	7%

(a) Represents volumes sold regardless of when produced.
(b) Oil and NGLs are converted at the rate of one barrel equals six mcfe based upon the approximate relative energy content of oil to 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.

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,		
	2013	2012	%	2013	2012	%
(Loss) income from operations before income taxes, as reported	$ (152)	$ 82,926	-100%	$149,579	$ 25,056	497%
Adjustment for certain special items:						
Gain (loss) on sale of assets	(3,162)	(61,836)		(92,291)	(49,132)	
Loss on ARO settlements	1,924	—		2,938	—	
Change in fair value related to derivatives prior to settlement	56,434	22,277		30,569	(2,737)	
Abandonment and impairment of unproved properties	5,852	21,230		51,918	125,278	
Loss on gas blending – brokered natural gas and marketing	3,271	—		7,070	—	
Loss on early extinguishment of debt	—	11,063		12,280	11,063	
Prior year Pennsylvania impact fee	—	501		—	25,208	
Impairment of proved property and other assets	—	34,273		7,753	35,554	
Lawsuit settlements	330	644		91,919	3,167	
Brokered natural gas and marketing – non-cash stock-based compensation	542	452		1,852	1,765	
Direct operating – non-cash stock-based compensation	699	768		2,755	2,415	
Exploration expenses – non-cash stock-based compensation	1,012	1,001		4,025	4,049	
General & administrative – non-cash stock-based compensation	21,137	13,786		55,737	44,541	
Deferred compensation plan – non-cash adjustment	22,039	(14,352)		55,296	7,203	
Income from operations before income taxes, as adjusted	109,926	112,733	-2%	381,400	233,430	63%
Income tax expense, as adjusted:						
Current	(143)	(1,778)		(143)	(1,778)	
Deferred	41,772	41,152		147,705	87,351	
Net income excluding certain items, a non-GAAP measure	$ 68,297	$ 73,359	-7%	$233,838	$147,857	58%
Non-GAAP income per common share						
Basic	$ 0.43	$ 0.46	-7%	$ 1.46	$ 0.93	57%
Diluted	$ 0.42	$ 0.46	-9%	$ 1.45	$ 0.92	58%
Non-GAAP diluted shares outstanding, if dilutive	161,496	160,559		161,407	160,307	

RANGE RESOURCES CORPORATION

HEDGING POSITION AS OF FEBRUARY 24, 2013 –
(Unaudited)

	Daily Volume	Hedge Price
Gas (Mmbtu)		
1Q 2014 Swaps	193,111	$4.16
1Q 2014 Collars	447,500	$3.84 - $4.48
2Q 2014 Swaps	200,000	$4.17
2Q 2014 Collars	447,500	$3.84 - $4.48
3Q 2014 Swaps	260,000	$4.18
3Q 2014 Collars	447,500	$3.84 - $4.48
4Q 2014 Swaps	260,000	$4.18
4Q 2014 Collars	447,500	$3.84 - $4.48
2015 Swaps	189,966	$4.17
2015 Collars	145,000	$4.07 - $4.56
2016 Swaps	27,500	$4.16
Oil (Bbls)		
1Q 2014 Swaps	8,500	$94.51
1Q 2014 Collars	2,000	$85.55 - $100.00
2Q 2014 Swaps	8,500	$94.51
2Q 2014 Collars	2,000	$85.55 - $100.00
3Q 2014 Swaps	9,500	$94.35
3Q 2014 Collars	2,000	$85.55 - $100.00
4Q 2014 Swaps	9,500	$94.35
4Q 2014 Collars	2,000	$85.55 - $100.00
2015 Swaps	6,000	$89.48
C2 Ethane (Bbls)		
1Q 2014 Swaps	689	$0.339
C3 Propane (Bbls)		
1Q 2014 Swaps	11,822	$1.015
2Q 2014 Swaps	12,000	$1.016
3Q 2014 Swaps	12,000	$1.018
4Q 2014 Swaps	12,000	$1.018
C4 Normal Butane (Bbls)		
1Q 2014 Swaps	3,656	$1.340
2Q 2014 Swaps	4,000	$1.344
3Q 2014 Swaps	4,000	$1.344
4Q 2014 Swaps	4,000	$1.344
C5 Natural Gasoline (Bbls)		
1Q 2014 Swaps	1,000	$2.113
2Q 2014 Swaps	1,000	$2.113

NOTE: SEE WEBSITE FOR OTHER SUPPLEMENTAL INFORMATION FOR THE PERIODS