RANGE ANNOUNCES THIRD QUARTER 2014 RESULTS

FORT WORTH, TEXAS, October 29, 2014…RANGE RESOURCES CORPORATION (NYSE: RRC) today announced its third quarter 2014 financial results.

Third Quarter Highlights –

- Range produced a record average of 1,209 Mmcfe per day, an increase of 26% over the prior year quarter
- Unit costs decreased $0.36 per mcfe or 10% compared to the prior year quarter
- Outstanding well results continue in the Marcellus
- New technology in Nora field yields best results in years with returns up to 100%
- 45 new gas purchase customers added to date in 2014
- New bank agreement announced with a maximum facility amount of $4.0 billion and reduced borrowing costs
- Credit upgrades announced from Standard and Poor's and Moody's

Commenting on the results, Jeff Ventura, Range's President and CEO, said, "Range set a record production level this quarter of over 1.2 Bcfe per day net to Range, driven by the Marcellus. It is exciting to see how far we have come since Range completed the Marcellus discovery well ten years ago this month. We are even more excited about future growth, as we capitalize on the first mover advantages Range enjoys in the Marcellus. This includes the largest net acreage position in Pennsylvania, specifically in southwest Pennsylvania, where we have leased the core of the highest hydrocarbon in place in the basin when considering stacked pay potential in the Marcellus, Utica and Upper Devonian. This also is the area that has the liquids-rich portion of the Marcellus and Upper Devonian. We have secured the lowest cost firm transportation portfolio of our peers which aligns with our production growth target of 20% to 25% per year. As these transportation contracts come into service, they will move an increasing portion of our natural gas and natural gas liquids to markets with strong year-round demand and stable index prices."

"Although the rapid growth in Marcellus production has created a challenging regional pricing environment for this quarter, looking ahead, prices are expected to improve. In addition, our liquids pricing, net of transportation costs, will be enhanced with the start-up of Mariner East. The propane portion is projected to start in early 2015 and the ethane portion in July 2015. We believe that as midstream projects come on line in 2015 and beyond, designed to move Marcellus gas to new markets with increasing levels of demand, the current supply/demand imbalance in the Appalachian basin will improve. As a first mover, with a low cost structure, strong balance sheet and a proven track record, Range is well-positioned to continue our annual 20% to 25% production growth to 3 Bcfe per day and beyond."

Operational Discussion

Range has updated its investor presentation. Please see www.rangeresources.com under the Investor Relations tab, "Presentations and Webcasts" area, for the presentation entitled, "Company Presentation – October 29, 2014."

Range produced a record average of 1,209 Mmcfe per day during the third quarter, consisting of 822.4 Mmcf per day of gas, 53,640 barrels of NGLs and 10,710 barrels per day of oil and condensate. Third quarter 2014 production exceeded the prior year quarter by 26% and the previous quarter by 9.4%. Production guidance for the fourth quarter is 1,350 Mmcfe per day, with 30% liquids. Annual production growth beyond 2014 is expected to be in the range of 20% to 25%.

Southern Marcellus Shale Division –

Production for the third quarter averaged 943 (778 net) Mmcfe per day for the division, a 36% increase over the prior year. The division's third quarter net production included 431 Mmcf per day of gas, 49,423 barrels per day of NGLs and 8,531 barrels per day of condensate.

During the third quarter, the division brought on line 28 wells in southwest Pennsylvania, with 19 wells in the super-rich area, six wells in the wet area and three wells in the dry area. The per well average 24-hour initial production rate ("IP") for the new wells averaged 15.9 (12.3 net) Mmcfe per day, (7.8 Mmcf per day of gas, 977 barrels per day of NGLs and 363 barrels per day of condensate), with an average lateral length of 4,660 feet with 24 stages.

In the wet and super-rich areas, the Company continued to drill and complete outstanding wells. In the super-rich area, one five well pad tested at an average 24-hour IP per well of 2,472 (2,302 net) boe per day with 71% liquids, or 14.8 Mmcfe per day (872 barrels of condensate, 876 barrels of NGLs and 4.3 Mmcf gas per day). The average per well lateral length was 4,225 feet with 21 stages. Another four well pad in the super rich area was brought on line at a per well average 24-hour IP of 2,850 (2,367 net) boe per day with 52% liquids, or 17.1 Mmcfe per day (513 barrels of condensate, 1,323 barrels of NGLs and 8.3 Mmcf gas per day). The average lateral length per well was 4,886 feet with 25 stages. In the wet area, a six well pad came on line at an average 24-hour IP per well of 16.5 (13.5 net) Mmcfe per day with 53% liquids (7.7 Mmcf of gas, 41 barrels of condensate and 1,423 barrel of NGLs per day). The average lateral length was 4,301 feet with 22 stages.

The division brought on line three wells in the dry gas area for the quarter. The per well average 24-hour IP per stage of the wells brought on line in the dry gas area was almost 1 Mmcfe per day per stage or a per well average 24-hour IP of 26.4 Mmcfe per day per well, with an average lateral length of 5,364 feet and 28 frac stages.

Range expects to turn to sales a total of 38 wells in the Southern Marcellus during the fourth quarter of 2014. Capital efficiencies have continued to improve, with several factors contributing to the improvement. Range will drill approximately 12% of its Marcellus wells in 2014 on existing pads, where it expects to benefit from improved landing target selection and completion techniques while at the same time avoiding the estimated cost of $850,000 for building a new pad and road at each location. Drilling efficiencies are continuing with Marcellus cost per lateral foot drilled decreasing by 15% in 2014 from $553 per lateral foot to $472 per lateral foot. The number of frac stages completed in 2014 has increased 55% compared to 2013. The Company is also expected to realize additional savings from optimizing existing gathering and compression infrastructure during production. For 2015, the average planned horizontal lateral will be 6,200 feet.

The Company recently set pipe on its initial dry gas Utica/Point Pleasant test in Washington County, Pennsylvania, the Claysville Sportsman's Club #1. The well is targeted to be completed with 32 frac stages using a reduced cluster spacing completion. The well was drilled from an existing Marcellus pad. Range will be conducting several scientific tests with extensive data collection on this well and anticipates that initial production results will be available in late December.

Northern Marcellus Shale Division –

In northeast Pennsylvania, production for the third quarter averaged 269 (228 net) Mmcfe per day for the division, a 25% increase over the prior year. During the third quarter, Range drilled six wells and turned seven wells to sales and is expecting to turn an additional seven wells to sales in the fourth quarter.

Production from a four well pad brought on line in the third quarter had a per well average 24-hour IP of 19.8 Mmcf per day. After 27 days on line, the wells produced at an average per well of 14.8 Mmcf per day. These four wells were drilled with an average lateral length of 4,885 feet and 25 frac stages. Lateral lengths and number of frac stages are expected to increase going forward, with laterals approaching 6,000 feet with 30 frac stages planned in 2015.

Midcontinent Division –

Production for the third quarter averaged 86 net Mmcfe per day for the division, a 9% decrease from the prior year. The division's third quarter net production included 49.2 Mmcf per day of gas, 4,106 barrels per day of NGLs and 2,011 barrels per day of oil.

During the third quarter, the Midcontinent division continued to evaluate results from geological modeling in the Mississippian Chat along the Nemaha ridge. Results are encouraging, as the last two quarters had the two highest average 24-hour IP rates achieved to date. The five wells brought on line in the third quarter averaged a per well 24-hour IP rate of 661 (534 net) boe per day with 72% liquids. The five wells had an average lateral length of 3,722 feet with 19 frac stages.

The second highest oil rate well this year came on line this quarter at a 24-hour IP of 1,165 (941 net) boe per day with 84% liquids (763 barrels oil, 210 barrels NGLs and 1,148 mcf gas per day). The highest oil rate well, announced in the previous quarter, had a 24-hour IP of 1,263 boe per day with 92% liquids (1,062 barrels oil, 98 barrels NGLs and 618 mcf gas per day). This highest oil rate well continues to perform well, averaging 877 boe per day with 88% liquids (679 barrels oil, 97 barrels NGLs and 606 mcf gas per day) for the first 30 days.

The division brought on line a St. Louis well in the third quarter that tested at a 24-hour peak rate of 9.6 (6.5 net) Mmcfe per day comprised of 6.1 Mmcfe gas, 286 barrels oil and 301 barrels NGLs per day. Year to date, six St. Louis wells have been brought on line, with a total 24-hour IP of 41.8 (22.8 net) Mmcfe per day total, with 34% liquids.

For the fourth quarter of 2014, the Company expects to bring on line three Mississippian Chat wells and one additional well in the Texas Panhandle.

Southern Appalachia Division –

Production for the third quarter averaged 113 (110 net) Mmcf per day for the division, a 52% increase over the prior year. The acquisition of EQT's 50% interest added approximately 40 Mmcf per day to third quarter production, compared to the second quarter of 2014.

Range had a full quarter of operational control over the Nora assets in Virginia during the third quarter after acquiring the remaining 50% working interest in the field and gathering system from EQT at the end of the second quarter 2014. In this short period of time, Range has already achieved some of the best results to date by utilizing a new well design coupled with a higher rate stimulation technique on both vertical coal bed methane (CBM) and vertical tight gas wells. With six wells turned to sales using this new design, CBM results are 100% better than the historical field average, with a modest increase of approximately $15,000 per well. Of particular note, one CBM well is producing at five times the average CBM well rate and early results indicate that it is the best CBM well drilled in the Nora field in 15 years.

Similar improvements have been achieved with the new designs on vertical tight gas wells, with results 70% better than the field average, with a cost increase of approximately $12,000 per well. With seven tight gas wells turned to sales using this new technique, the 30-day well production average of these wells is the highest in over 10 years.

In the third quarter, the division turned to sales seven tight gas wells, two CBM wells and one horizontal Huron shale well. Fourth quarter plans include bringing on line 10 additional tight gas wells, 14 CBM wells, three horizontal Huron wells and performing recompletions and workovers on 10 CBM wells. Continued expansion in Virginia will utilize the 130 Mmcf per day of current existing capacity within the Nora gathering system. Gas markets remain strong in the Southeast with Range receiving approximately $0.20 above NYMEX for production from the Nora field.

Marcellus Shale Marketing, Transportation and Processing Update-

In the early stages of the Marcellus play, Range anticipated that successful development would inevitably create a regional oversupply beyond what local demand could absorb. At that time, Range began focusing its marketing efforts on developing new markets outside the Appalachian basin, along with securing transportation arrangements at a reasonable cost to serve these markets. As a result, Range anticipates having the capability of selling Appalachian gas to a customer base that stretches from the Northeast to the Upper Midwest, the Gulf Coast and Texas, Florida and the Atlantic Coast. To this end, the Company has added 45 new natural gas customers so far in 2014. This has allowed Range to diversify its natural gas pricing, as we expect to move gas to over 20 different indices by 2018. Accordingly, the Company expects its Marcellus price realizations to improve in the years ahead compared to prices being received in Appalachia today, given the almost 34 Bcf per day of announced Appalachian basin pipeline takeaway projects that are expected to be in service by the end of 2018. Range expects that long-term differentials in Appalachia will ultimately equal the cost of transport out of the basin.

At the end of the third quarter, Range has contracts in place for approximately 1.1 Bcf per day of transportation capacity, increasing to 2.4 Bcf per day by 2018. Range's objective has been to layer in additional commitments that follow the Company's growing production volumes. These future capacity additions, to multiple markets outside the Appalachian region, will support Range's growth while maximizing net realized gas prices. As a result of discovering the Marcellus and being a first mover in securing transportation, Range has been able to secure its firm transportation and firm sales through 2016 at an expected average cost of $0.28 per Mmbtu in 2016, rising to $0.39 through 2018. Range expects that costs can be further reduced with our contractual marketing arrangements. Importantly, the Company has the option to renew many of these transportation agreements at the currently contracted rate.

Range is the largest producer of wet gas and NGLs in the Appalachian basin, with the most comprehensive and diversified plan to move our growing volumes of gas, NGLs and condensate. Similar to the Company's natural gas diversification strategy, its existing NGL contracts and commitments are intended to ensure Range can move all products to new and growing markets at prices greater than what would alternatively be realized in local markets. The Mariner East project provides Range benefits on propane and ethane. In early 2015, the propane portion of Mariner East is expected to be operational, allowing Range to continue selling propane to international markets, but at significantly lower transportation cost to Sunoco's Marcus Hook facility in Philadelphia. The project also adds size and scale, opening up the potential for other marketing options. Mariner East is expected to further diversify and strengthen Range's ethane marketing abilities when it becomes operational in July 2015 by selling ethane to INEOS for use in its European petrochemical facilities.

Range has recently posted a presentation to our website entitled "Takeaway Capacity in Appalachia" that explains many of the macro dynamics that have occurred in the Appalachian basin due to the rapid growth of Marcellus production, the outlook for the future and Range's strategy regarding the current and future challenges.

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.)

GAAP revenues for the third quarter of 2014 totaled $617 million (39% increase as compared to third quarter 2013), GAAP net cash provided from operating activities including changes in working capital was $213 million versus $223 million in the third quarter 2013 and GAAP earnings were $146 million ($0.86 per diluted share) versus net income of $19 million ($0.12 per diluted share) in the third quarter 2013, an increase of 663%.

Several non-cash or non-recurring items impacted third quarter results. A $125 million favorable non-cash mark-to-market gain on derivatives, a $46 million mark-to-market gain due to the decrease in value of the Company's common stock held in the Company deferred compensation plan (which was fully funded on the date of grant), $13.4 million for abandonment and impairment of unproved properties, a $4.9 million fine for water handling and storage issues and $14 million of non-cash stock compensation expenses were recorded.

Non-GAAP revenues for third quarter 2014 totaled $491 million (13% increase as compared to third quarter 2013), cash flow from operations before changes in working capital, a non-GAAP measure ("adjusted cash flow"), reached $257 million (a 5% increase as compared to third quarter 2013). Adjusted net income, a non-GAAP measure, for third quarter 2014 was $62 million (an 8% increase as compared to third quarter 2013).

Total unit costs improved by $0.36 per mcfe or 10% compared to the prior-year quarter, with the largest decreases in interest expense, production and ad valorem taxes and depreciation, depletion and amortization expense.

Third quarter production volumes averaged 1,209 Mmcfe per day, a 26% increase over the prior-year quarter. Year-over-year gas production increased 11%, NGL production rose 109%, while oil and condensate production was down 3%, primarily due to the Conger property exchange in late second quarter, representing approximately 9% of oil and condensate volumes for the quarter. The third quarter 2014 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which would correspond to analysts' estimates, a non-GAAP measure) averaged $4.16 per mcfe, a 13% decrease over the prior-year quarter of $4.80 per mcfe, partially due to the Conger exchange in second quarter 2014.

- Production and realized prices after hedging for each commodity for the third quarter of 2014 were: natural gas – 822 Mmcf per day ($3.63 per mcf), NGLs – 53,640 barrels per day ($22.53 per barrel) and crude oil and condensate – 10,710 barrels per day ($78.66 per barrel).

- The third quarter average natural gas realized price before hedging settlements was $3.34. Financial hedges based upon NYMEX increased realizations by $0.06 per mcf while financial basis hedges increased realizations by $0.22 per mcf during the quarter. The average Company natural gas differential including the settled financial basis hedges but before NYMEX hedging for the third quarter was $(0.49) per mcf compared to $(0.58) per mcf for the second quarter 2014. *(See the schedule below which details the components of the non-GAAP average realized natural gas price for the quarter and the tables presented elsewhere that reconcile the non-GAAP measures to their most directly comparable GAAP financial measure.)*

- NGL pricing before the impact of hedging was 23% of WTI or $22.26 per barrel for the third quarter of 2014 ($22.53 per barrel after hedging, hedging added $0.27 per barrel). Ethane was approximately 50% of the total composite barrel in the Marcellus during the quarter.

- Crude oil and condensate price realizations, before financial hedges, for the third quarter averaged 84% of WTI or $81.34 per barrel ($78.66 per barrel after hedging, hedging reduced realizations by $2.68 per barrel).

Range is one of the few producers in the Appalachian basin currently extracting ethane. Importantly, due to the favorable pricing reflected in Range's existing and unique ethane contracts, ethane extraction increases cash flow, as shown in the tables below, compared to leaving ethane in the gas stream and being paid for the increased Btu content of the gas (ethane rejection). As ethane extraction increases our cash flow, it will also <u>increase</u> NGL volumes, but will <u>decrease</u> the average price for both natural gas and NGLs, which should be considered when comparing Range's price realizations versus producers who reject ethane.

Range Resources SW Marcellus - Third Quarter 2014

	3Q Pro-forma	3Q Actual	3Q Pro-forma
	3Q 2014 assuming no ethane recovery	Transportation and processing costs shown as separate expense rather than deduct to NGL price	3Q 2014 assuming full ethane recovery and utilization of all three ethane and propane projects
Gross Revenue, pre-hedge			
Natural gas (per mcf)	$ 3.64	$ 3.49	$ 3.47
Natural gas liquids (per bbl)	44.25	29.71	30.73
Condensate (per bbl)	78.04	78.04	78.04
Total revenue (per mcfe)	**5.23**	**4.67**	**4.76**
Operating Expenses (per mcfe)			
Direct operating	0.25	0.21	0.21
Transport, gathering & processing *	1.71	1.47	1.46
Production tax (impact fee)	0.09	0.08	0.08
Cash Production Cost	**2.05**	**1.76**	**1.75**
Cash Production Margin (per mcfe)	**$ 3.18**	**$ 2.91**	**$ 3.01**
Cash Flow (millions)	**$ 196**	**$ 208**	**$ 223**

* Includes expense associated with ethane and propane transportation agreements, such as ATEX or Mariner East. For this illustration, NGL processing fees, and truck and rail expenses are also included as an expense rather than a reduction to NGL price, as would be typical for GAAP purposes.

Range expects that with the propane and ethane volumes being shipped on Mariner East in 2015, the incremental uplift in cash flow will reach $100 million on an annualized basis.

New Bank Agreement Signed and Credit Ratings Upgraded

Subsequent to the end of the quarter, Range announced that it amended and restated its revolving credit facility. The new five-year agreement has a maximum facility size of $4 billion, with an initial borrowing base of $3 billion and $2 billion in commitments. This represents an increase in the borrowing base of $1 billion and increased commitments of $250 million. The agreement also reduces drawn borrowing costs by 25 basis points and grants Range the option to release all collateral upon the receipt of a single investment grade rating. The maturity date is extended to October 16, 2019. On October 16, Standard & Poor's Ratings Services announced it had upgraded Range's corporate credit rating to BB+. Earlier in September, Moody's Investors Service upgraded Range's outlook to 'Positive' with a current corporate rating of Ba1.

Capital Expenditures

Third quarter drilling expenditures of $341 million funded the drilling of 71 (68 net) wells and the completion of previously drilled wells. A 100% drilling success rate was achieved. In addition, during the third quarter, $36 million was expended on acreage, $6 million on gas gathering systems and $10 million for exploration expense. Range is on track with its 2014 capital expenditure budget of $1.52 billion.

Guidance – Fourth Quarter 2014

Production Guidance:

Production growth for 2014 is targeted at 25% year-over-year. Average daily production for the fourth quarter is expected to be approximately 1.35 Bcfe per day, with 30% liquids.

Guidance for 2014 Activity:

Under the current plan, which is still subject to change, Range expects to turn to sales approximately 76 wells during the fourth quarter in the Marcellus, Nora and Midcontinent, as shown below:

	Total Wells to Sales YTD	Expected Remaining Wells to Sales in 4Q 2014	Planned Total Wells to Sales in 2014
Super-Rich area	44	13	57
Wet area	24	21	45
Dry area-SW	9	4	13
Dry area-NE	13	7	20
Total Marcellus	90	45	135
Nora area	19	27	46
Midcontinent	19	4	23
Total	**128**	**76**	**204**

4Q 2014 Expense per mcfe Guidance:

Direct operating expense	$0.29 - $0.32 per mcfe
Transportation, gathering and compression expense	$0.76 - $0.78 per mcfe
Production tax expense	$0.11 - $0.13 per mcfe
Exploration expense	$26 - $29 million
Unproved property impairment expense	$15 - $18 million
G&A expense	$0.33 - $0.35 per mcfe
Interest expense	$0.30 - $0.33 per mcfe
DD&A expense	$1.28 - $1.30 per mcfe

Non-GAAP Natural Gas Price Realizations and Differentials

Range continues to hedge a significant portion of its estimated future production in order to lock in prices and returns which provide certainty of cash flow to execute our capital plans. During the third quarter, most Appalachian price indices continued to weaken as additional supply growth outpaced regional demand and infrastructure to export natural gas out of the basin. Range offset some of this regional weakness by hedging basis, as reflected in the $0.22 gain per mcf on basis hedging in the third quarter, resulting in a corporate differential of $0.49 below NYMEX. Range has hedged Marcellus and other basis for 370,000 Mmbtu per day for October 2014, 95,000 Mmbtu per day from November 2014 through March 2015, and 5,000 Mmbtu per day for April 2015 through October 2015. The fair value of the basis hedges based upon future strip prices as of September 30, 2014 was a gain of $12.7 million for the fourth quarter 2014, a loss of $14.3 million for first quarter 2015 and a gain of $120,000 for the remainder of 2015. The table below shows the components of the non-GAAP measure of "average natural gas realized prices" for the last five quarters for comparative purposes as it would be calculated by analysts. A similar analysis is shown on the Company's website for NGLs and condensate and crude oil.

Corporate Differential Disclosure	3Q 2013	4Q 2013	1Q 2014	2Q 2014	3Q 2014
NYMEX Index average price	**$3.60**	**$3.62**	**$4.92**	**$4.67**	**$4.05**
Differential under GAAP reporting (1)	($0.17)	($0.22)	$0.66	($0.60)	($0.71)
Cash settled basis hedging	$0.00	($0.01)	($0.90)	$0.02	$0.22
Differential including basis hedging	**($0.17)**	**($0.23)**	**($0.24)**	**($0.58)**	**($0.49)**
Average price before NYMEX hedges	$3.43	$3.39	$4.68	$4.09	$3.56
Cash settled NYMEX hedges	$0.45	$0.45	($0.49)	($0.21)	$0.07
Average price including all hedges	**$3.88**	**$3.84**	**$4.19**	**$3.88**	**$3.63**

(1) Midcontinent Division realized sales prices contain certain processing and gathering charges, resulting in an approximately $0.60 negative effect on the GAAP reported differential for the division

Basis Differentials:

Based upon the contracts that Range has in place for the periods disclosed and the future basis differential indications from quotations on ICE (the "Intercontinental Exchange") as of October 24, 2014, the calculated differential in each division would be the amounts shown in the table below. Basis at the various receipt points which we sell natural gas are inherently volatile, have wide spreads between the bid and ask indications and change on a daily basis. The table below represents the Company's calculated differentials at a point in time (October 24, 2014), not an expected future realized price. The percentages of expected production to be sold by indices are shown in the corporate presentation posted on the website and should be used along with the table below in modeling the expected differentials by division adjusted for the weighted average change in the indices from October 24, 2014 to the measurement date for each month. For comparative purposes, a table of historical basis settlements and actual differentials by division is included in Table 9 of the Supplemental Tables for third quarter 2014 on the Company's website.

DIFFERENTIALS BY DIVISION

	Actual 3Q 2014		Calculated Estimates by Division 4Q 2014		1Q 2015	
			Based on NYMEX			
Marcellus						
SW PA	$	(0.56)	$	(0.55)	$	+ 0.25
NE PA		(1.44)		(1.57)		(1.20)
Nora		+ 0.25		+ 0.20		+ 0.20
Midcontinent [(1)]		(0.76)		(0.80)		(0.80)
Basis Hedging		+ 0.22		+ 0.17		(0.12)
Corporate Differential	$	(0.49)	$	(0.58)	$	(0.31)

(1) Midcontinent processing, gathering and transportation costs are netted against the realized price received from a third party which increases the differential by approximately $0.60.

NYMEX 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 remaining 2014 natural gas production hedged at a weighted average floor price of $3.96 per Mmbtu and a weighted average ceiling price of $4.38 per Mmbtu. Similarly, Range has hedged more than 90% of its remaining 2014 projected crude oil production at a floor price of $92.82 per barrel and approximately 50% of its composite NGL production.

For calendar year 2015, Range has hedged 452,000 Mmbtu per day of its expected natural gas production at a weighted average floor price of $4.16 per Mmbtu and a weighted average ceiling price of $4.32 per Mmbtu. Similarly, Range has hedged 9,600 barrels per day of its 2015 projected crude oil production at a floor price of $90.57 per barrel with less than 5% of its expected NGL production currently hedged due to the backwardation of the future price curve. Please see Range's detailed hedging schedule posted at the end of the financial tables below and on its website at www.rangeresources.com.

As of September 30, 2014, Range had basis hedge contracts covering 370,000 Mmbtu per day for October 2014, 95,000 Mmbtu per day for November 2014 through March 2015 and 5,000 Mmbtu per day for April 2015 through October 2015.

Effective March 1, 2013, Range elected to discontinue hedge accounting 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 September 30, 2014, the Company expects to reclassify into earnings in the fourth quarter of 2014, $358,000 of unrealized losses frozen in accumulated other comprehensive loss due to the discontinuance of hedge accounting.

Conference Call Information

A conference call to review the financial results is scheduled on Thursday, October 30 at 9:00 a.m. ET. To participate in the call, please dial 877-407-0778 and ask for the Range Resources third quarter 2014 financial results conference call. A replay of the call will be available through November 30. To access the phone replay dial 877-660-6853. The conference ID is 13592168.

A simultaneous webcast of the call may be accessed over the Internet at www.rangeresources.com. The webcast will be archived for replay on the Company's website until November 30.

Non-GAAP Financial Measures:

Adjusted net income comparable to analysts' estimates as set forth in this release represents income or loss 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 and 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 or loss 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 along with non-GAAP revenue disclosures.

Cash flow from operations before changes in working capital (sometimes referred to as "adjusted cash flow") 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.

The Company discloses in this release the detailed components of many of the single line items shown in the unaudited GAAP financial statements included in the Company's Quarterly Report on Form 10-Q. The Company believes that it is important to furnish this detail of the various components comprising each line of the Statements of Operations to better inform the reader of the details of each amount, the changes between periods and the effect on its financial results.

Hedging and Derivatives

As discussed 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 undesignated hedges and 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-Q along with the change in mark-to-market valuations of such unrealized derivatives. Effective March 1, 2013, the Company de-designated all commodity contracts and elected to discontinue hedge accounting prospectively. 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 Midcontinent 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 rangeresources.com.

All statements, except for statements of historical fact, made in this release such as expected future growth in production, future transportation capacity and sales, expected midstream additions, future cash flow growth, future commodity prices, expected demand growth, future capital spending levels, cost structure improvements, expected capital efficiency gains, expected improvements in well results, expected future efficiencies, expected price realizations, expected future customers, expected timing of well results, future rates of return 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 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. Investors are urged to consider closely the reserves 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.*

2014-21

SOURCE: Range Resources Corporation

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RANGE RESOURCES CORPORATION

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	%	2014	2013	%
Revenues and other income:						
Natural gas, NGLs and oil sales (a)	$446,067	$431,214		$1,495,601	$1,267,131	
Derivative fair value (loss)/income	142,057	(40,355)		(28,902)	(2,470)	
Gain on sale of assets	167	6,008		281,878	89,129	
Brokered natural gas, marketing and other (b)	28,118	9,213		91,641	40,737	
Brokered natural gas – blending (b)	-	36,278		-	40,216	
Equity method investment (b)	-	268		(277)	541	
ARO settlement gain (loss) (b)	135	(832)		(651)	(1,014)	
Other (b)	71	244		191	363	
Total revenues and other income	616,615	442,038	39%	1,839,481	1,434,633	28%
Costs and expenses:						
Direct operating	37,072	30,208		109,013	91,675	
Direct operating – non-cash stock-based compensation (c)	720	699		3,509	2,056	
Transportation, gathering and compression	84,777	60,958		235,747	189,422	
Production and ad valorem taxes	10,110	11,454		32,632	33,950	
Brokered natural gas and marketing	28,050	10,588		95,296	44,769	
Brokered natural gas and marketing – non-cash stock-based compensation (c)	656	531		2,314	1,310	
Brokered natural gas and marketing – blending	-	39,998		-	44,015	
Exploration	10,410	19,513		36,502	47,331	
Exploration – non-cash stock-based compensation (c)	1,033	983		3,408	3,013	
Abandonment and impairment of unproved properties	13,444	11,692		32,771	46,066	
General and administrative	37,255	33,564		109,854	104,525	
General and administrative – non-cash stock-based compensation (c)	11,556	11,031		43,856	34,600	
General and administrative – lawsuit settlements	1,252	324		2,203	91,589	
General and administrative – bad debt expense	-	-		250	250	
General and administrative – DEP penalty	4,900	-		4,900	-	
Deferred compensation plan (d)	(46,198)	(2,225)		(37,714)	33,257	
Interest expense	39,188	44,321		130,077	131,602	
Loss on early extinguishment of debt	-	-		24,596	12,280	
Depletion, depreciation and amortization	142,450	130,343		404,493	365,439	
Impairment of proved properties and other assets	-	7,012		24,991	7,753	
Total costs and expenses	376,675	410,994	-8%	1,258,698	1,284,902	-2%
Income from continuing operations before income taxes	239,940	31,044	673%	580,783	149,731	288%
Income tax expense:						
Current	-	-		5	-	
Deferred	93,522	11,866		230,450	62,180	
	93,522	11,866		230,455	62,180	
Net income	$146,418	$ 19,178	663%	$350,328	$ 87,551	300%
Net Income Per Common Share:						
Basic	$ 0.87	$ 0.12		$ 2.11	$ 0.54	
Diluted	$ 0.86	$ 0.12		$ 2.10	$ 0.53	
Weighted average common shares outstanding, as reported:						
Basic	165,841	160,500	3%	162,866	160,398	2%
Diluted	166,460	161,374	3%	163,685	161,321	1%

(a) See separate natural gas, NGLs and oil sales information table.
(b) Included in Brokered natural gas, marketing and other revenues in the 10-Q.
(c) 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-Q.
(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)	September 30, 2014 (Unaudited)	December 31, 2013 (Audited)
Assets		
Current assets	$189,858	$192,466
Derivative assets	44,774	4,421
Deferred tax assets	2,010	51,414
Natural gas and oil properties, successful efforts method	7,630,085	6,758,437
Transportation and field assets	38,555	32,784
Other	129,168	259,564
	$8,034,450	$7,299,086
Liabilities and Stockholders' Equity		
Current liabilities	$461,375	$464,326
Asset retirement obligations	5,037	5,037
Derivative liabilities	-	26,198
Bank debt	649,000	500,000
Subordinated notes	2,350,000	2,640,516
	2,999,000	3,140,516
Deferred tax liability	948,904	771,980
Derivative liabilities	-	25
Deferred compensation liability	197,277	247,537
Asset retirement obligations and other liabilities	253,940	229,015
	1,400,121	1,248,557
Common stock and retained earnings	3,172,227	2,411,853
Common stock held in treasury stock	(3,088)	(3,637)
	3,169,139	2,408,216
Accumulated other comprehensive income	(222)	6,236
Total stockholders' equity	3,168,917	2,414,452
	$8,034,450	$7,299,086

RECONCILIATION OF TOTAL REVENUES AND OTHER INCOME TO TOTAL REVENUE EXCLUDING CERTAIN ITEMS, a non-GAAP measure

(Unaudited, in thousands)	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	%	2014	2013	%
Total revenues and other income, as reported	$616,615	$442,038	40%	$1,839,481	$1,434,633	28%
Adjustment for certain special items:						
Total change in fair value related to derivatives prior to settlement (gain) loss	(125,154)	33,404		(84,957)	(25,865)	
ARO settlement (gain) loss	(135)	832		651	1,014	
(Gain) loss on sale of assets	(167)	(6,008)		(281,878)	(89,129)	
Brokered natural gas – blending	-	(36,278)		-	(40,216)	
Total revenues, as adjusted, non-GAAP	$491,159	$433,988	13%	$1,473,297	$1,280,437	15%

RANGE RESOURCES CORPORATION

CASH FLOWS FROM OPERATING ACTIVITIES
(Unaudited, in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$146,418	$ 19,178	$350,328	$ 87,551
Adjustments to reconcile net cash provided from continuing operations:				
(Gain) loss from equity investment, net of distributions	-	378	3,096	(1,174)
Deferred income tax expense	93,522	11,866	230,450	62,180
Depletion, depreciation, amortization and impairment	142,450	137,355	429,484	373,192
Exploration dry hole costs	-	4,063	1	3,904
Abandonment and impairment of unproved properties	13,444	11,692	32,771	46,066
Derivative fair value loss (income)	(142,057)	40,355	28,902	2,470
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	16,903	(6,951)	(113,859)	(28,335)
Allowance for bad debts	-	-	250	250
Amortization of deferred issuance costs, loss on extinguishment of debt, and other	1,618	3,073	31,430	19,735
Deferred and stock-based compensation	(32,426)	10,862	15,486	74,187
Gain on sale of assets and other	(167)	(6,008)	(281,878)	(89,129)
Changes in working capital:				
Accounts receivable	11,823	8,651	13,098	6,508
Inventory and other	1,537	1,714	(5,335)	3,259
Accounts payable	(33,470)	(18,853)	(13,355)	(29,234)
Accrued liabilities and other	(6,180)	5,602	(65,931)	(28,564)
Net changes in working capital	(26,290)	(2,886)	(71,523)	(48,031)
Net cash provided from operating activities	$213,415	$222,977	$654,938	$502,866

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net cash provided from operating activities, as reported	$213,415	$222,977	$654,938	$502,866
Net changes in working capital	26,290	2,886	71,523	48,031
Exploration expense	10,410	15,450	36,501	43,427
Lawsuit settlements	1,252	324	2,203	91,589
DEP penalty	4,900	-	4,900	-
Equity method investment distribution / intercompany elimination	-	(646)	(2,819)	632
Loss on gas blending	-	3,720	-	3,799
Non-cash compensation adjustment	304	213	246	436
Cash flow from operations before changes in working capital – a non-GAAP measure	$256,571	$244,924	$767,492	$690,780

ADJUSTED WEIGHTED AVERAGE SHARES OUTSTANDING
(Unaudited, in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Basic:				
Weighted average shares outstanding	168,697	163,407	165,675	163,155
Stock held by deferred compensation plan	(2,856)	(2,907)	(2,809)	(2,757)
Adjusted basic	165,841	160,500	162,866	160,398
Dilutive:				
Weighted average shares outstanding	168,697	163,407	165,675	163,155
Dilutive stock options under treasury method	(2,237)	(2,033)	(1,990)	(1,834)
Adjusted dilutive	166,460	161,374	163,685	161,321

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 September 30,			Nine Months Ended September 30,		
	2014	2013	%	2014	2013	%
Natural gas, NGL and oil sales components:						
Natural gas sales	$252,562	$233,019		$874,514	$718,176	
NGL sales	109,858	77,317		355,360	211,475	
Oil sales	80,144	93,473		255,146	243,057	
Cash-settled hedges (effective):						
Natural gas	1,966	25,870		6,760	90,693	
Crude oil	1,537	1,535		3,821	3,730	
Total oil and gas sales, as reported	$446,067	$431,214	3%	$1,495,601	$1,267,131	18%
Derivative fair value income (loss), as reported:	$142,057	$(40,355)		$(28,902)	$(2,470)	
Cash settlements on derivative financial instruments – (gain) loss:						
Natural gas	(19,762)	(4,961)		83,983	18,358	
NGLs	(1,323)	3,907		13,114	1,759	
Crude Oil	4,182	8,005		16,762	8,218	
Total change in fair value related to derivatives prior to settlement, a non GAAP measure	$125,154	$(33,404)		$84,957	$25,865	
Transportation, gathering and compression components:						
Natural gas	$72,186	$57,576		$205,764	$179,571	
NGLs	12,591	3,382		29,983	9,851	
Total transportation, gathering and compression, as reported	$84,777	$60,958		$235,747	$189,422	
Natural gas, NGL and oil sales, including cash-settled derivatives: (c)						
Natural gas sales	$274,290	$263,850		$797,291	$790,511	
NGL sales	111,181	73,410		342,246	209,716	
Oil sales	77,499	87,003		242,205	238,569	
Total	$462,970	$424,263	9%	$1,381,742	$1,238,796	12%
Production of oil and gas during the periods (a):						
Natural gas (mcf)	75,665,182	68,024,813	11%	205,444,379	194,975,047	5%
NGL (bbl)	4,934,882	2,362,340	109%	13,877,217	6,367,253	118%
Oil (bbl)	985,300	1,018,013	-3%	3,010,054	2,795,192	8%
Gas equivalent (mcfe) (b)	111,186,274	88,306,931	26%	306,768,005	249,949,717	23%
Production of oil and gas – average per day (a):						
Natural gas (mcf)	822,448	739,400	11%	752,544	714,194	5%
NGL (bbl)	53,640	25,678	109%	50,832	23,323	118%
Oil (bbl)	10,710	11,065	-3%	11,026	10,239	8%
Gas equivalent (mcfe) (b)	1,208,546	959,858	26%	1,123,692	915,567	23%
Average prices, including cash-settled hedges that qualify for hedge accounting before third party transportation costs:						
Natural gas (mcf)	$ 3.36	$ 3.81	-12%	$ 4.29	$ 4.15	3%
NGL (bbl)	$ 22.26	$ 32.73	-32%	$ 25.61	$ 33.21	-23%
Oil (bbl)	$ 82.90	$ 93.33	-11%	$ 86.03	$ 88.29	-3%
Gas equivalent (mcfe) (b)	$ 4.01	$ 4.88	-18%	$ 4.88	$ 5.07	-4%
Average prices, including cash-settled hedges and derivatives before third party transportation costs: (c)						
Natural gas (mcf)	$ 3.63	$ 3.88	-7%	$ 3.88	$ 4.05	-4%
NGL (bbl)	$ 22.53	$ 31.08	-27%	$ 24.66	$ 32.94	-25%
Oil (bbl)	$ 78.66	$ 85.46	-8%	$ 80.47	$ 85.35	-6%
Gas equivalent (mcfe) (b)	$ 4.16	$ 4.80	-13%	$ 4.50	$ 4.96	-9%
Average prices, including cash-settled hedges and derivatives: (d)						
Natural gas (mcf)	$ 2.67	$ 3.03	-12%	$ 2.88	$ 3.13	-8%
NGL (bbl)	$ 19.98	$ 29.64	-33%	$ 22.50	$ 31.39	-28%
Oil (bbl)	$ 78.66	$ 85.46	-8%	$ 80.47	$ 85.35	-6%
Gas equivalent (mcfe) (b)	$ 3.40	$ 4.11	-17%	$ 3.74	$ 4.20	-11%
Transportation, gathering and compression expense per mcfe	$ 0.76	$ 0.69	10%	$ 0.77	$ 0.76	1%

(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.

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 September 30,			Nine Months Ended September 30,		
	2014	2013	%	2014	2013	%
Income from operations before income taxes, as reported	$239,940	$31,044	673%	$580,783	$149,731	288%
Adjustment for certain special items:						
Gain on sale of assets	(167)	(6,008)		(281,878)	(89,129)	
ARO settlements (gain) loss	(135)	832		651	1,014	
Change in fair value related to derivatives prior to settlement	(125,154)	33,404		(84,957)	(25,865)	
Abandonment and impairment of unproved properties	13,444	11,692		32,771	46,066	
Loss on gas blending – brokered natural gas and marketing	-	3,720		-	3,799	
Loss on early extinguishment of debt	-	-		24,596	12,280	
Impairment of proved property and other assets	-	7,012		24,991	7,753	
Lawsuit settlements	1,252	324		2,203	91,589	
DEP Penalty	4,900	-		4,900	-	
Brokered natural gas and marketing – non cash stock-based compensation	656	531		2,314	1,310	
Direct operating – non-cash stock-based compensation	720	699		3,509	2,056	
Exploration expenses – non-cash stock-based compensation	1,033	983		3,408	3,013	
General & administrative – non-cash stock-based compensation	11,556	11,031		43,856	34,600	
Deferred compensation plan – non-cash adjustment	(46,198)	(2,225)		(37,714)	33,257	
Income from operations before income taxes, as adjusted	101,847	93,039	9%	319,433	271,474	18%
Income tax expense, as adjusted						
Current	-	-		5	-	
Deferred	39,696	35,562		123,780	105,933	
Net income excluding certain items, a non-GAAP measure	$ 62,151	$ 57,477	8%	$195,648	$165,541	18%
Non-GAAP income per common share						
Basic	$ 0.37	$ 0.36	3%	$ 1.20	$ 1.03	17%
Diluted	$ 0.37	$ 0.36	3%	$ 1.20	$ 1.03	17%
Non-GAAP diluted shares outstanding, if dilutive	166,460	161,374		163,685	161,321	

RANGE RESOURCES CORPORATION

HEDGING POSITION AS OF OCTOBER 29, 2014 –
(Unaudited)

	Daily Volume	Hedge Price
Gas (Mmbtu)		
4Q 2014 Swaps	260,000	$4.18
4Q 2014 Collars	447,500	$3.84 - $4.48
2015 Swaps	307,432	$4.21
2015 Collars	145,000	$4.07 - $4.56
2016 Swaps	90,000	$4.21
Oil (Bbls)		
4Q 2014 Swaps	9,500	$94.35
4Q 2014 Collars	2,000	$85.55 - $100.00
2015 Swaps	9,626	$90.57
2016 Swaps	1,000	$91.43
C3 Propane (Bbls)		
4Q 2014 Swaps	12,000	$1.018
2015 Swaps	1,745	$1.042
C4 Normal Butane (Bbls)		
4Q 2014 Swaps	4,000	$1.344
C5 Natural Gasoline (Bbls)		
4Q 2014 Swaps	3,500	$2.168
2015 Swaps	123	$2.140

NOTE: SEE WEBSITE FOR OTHER SUPPLEMENTAL INFORMATION FOR THE PERIODS