



Range Announces Fourth Quarter and Year-End 2017 Results

February 27, 2018

FORT WORTH, Texas, Feb. 27, 2018 (GLOBE NEWSWIRE) -- **RANGE RESOURCES CORPORATION** (NYSE:RRC) today announced its fourth quarter and year-end 2017 financial results.

Highlights –

- GAAP earnings for 2017 reached \$333 million (\$1.34 per diluted share) versus a loss of \$521 million (\$2.75 per diluted share) in 2016
- Net cash provided from operating activities in 2017 increased to \$816 million in 2017 compared to \$387 million in 2016, an increase of 111%
- GAAP revenues increased to \$2.6 billion in 2017 compared to \$1.1 billion in 2016, an increase of 137%
- Production increased to 2.0 Bcfe per day in 2017 compared to 1.5 Bcfe per day in 2016, an increase of 30%
- Southwest Marcellus production in fourth quarter 2017 increased to 1,657 net Mmcf per day, a 34% increase over the prior year

Commenting, Jeff Ventura, the Company's CEO said, "Financial results were much improved in 2017 with increases in earnings, cash flow, revenues and production compared to 2016. Operationally, the Marcellus continues to drive growth and profitability, with increasing capital efficiency. Outstanding Marcellus drilling results during the year expanded the core Marcellus drilling inventory in all directions. Our marketing strategy, which will be fully implemented in 2018 after years of planning, is expected to improve margins going forward as Range will be positioned to access growing demand for natural gas and NGLs, particularly in the expanding export markets. We are slowing activity in North Louisiana following disappointing results in 2017, which will allow time for additional technical analysis that we expect will improve results in 2018.

As shown in our five-year outlook, we expect to grow production by approximately 11% annually, while generating greater than \$1 billion in cumulative free cash flow. With Range's long-life inventory of over 4,000 high-quality drilling locations, extensive transportation network and ability to add reserves at some of the lowest costs in the industry, we believe Range is well positioned to generate shareholder value for many years, while also significantly strengthening the balance sheet."

Range previously announced 2017 proved reserves results and a five-year outlook on January 24, 2018. Highlights from these announcements were:

2017 Proved Reserves Results

- Proved reserves increased by 26% to 15.3 Tcfe
- SEC PV₁₀ reserve value increased by 119% to \$8.1 billion
- Record low drill-bit finding costs were \$0.31 per mcf

Five-Year Outlook

- ~\$1 billion in cumulative free cash flow from 2018 through 2022
- Leverage below 2x net debt to EBITDAX in 2022, without asset sales
- 13% production CAGR on a debt-adjusted per share basis
- 3,200 core Marcellus locations remaining after the 5 year period ending in 2022

2018 Capital Spending Plans

Range's 2018 capital budget is \$941 million. At year-end strip pricing, this is expected to be less than cash flow, with the excess cash flow expected to be used to reduce debt. In addition, any proceeds received from asset sales are also expected to be applied to reduce debt.

Approximately 85% of the capital budget is expected to be allocated to the Appalachia division and 15% to the North Louisiana division. The budget includes projected service cost increases in 2018. In Appalachia, approximately 60% of activity will be directed towards liquids-rich drilling, where successful drilling in 2017 led to improved type curves in the Company's super-rich area. In addition, Range's liquids-rich acreage has an extensive inventory of existing pads that reduce capital costs and gathering expense. The acreage is also in close proximity to capacity for both existing and expected NGL and natural gas takeaway projects, improving netback pricing. The Company expects production of approximately 2.23 Bcfe per day in 2018, which equates to 11% growth compared to 2017.

The 2018 capital budget includes approximately \$857.4 million for drilling and recompletions (91% of the total), \$54 million for leasehold, \$4.3 million for seismic, and \$25.5 million for pipelines, facilities and other capital expenditures. The budget includes 100 wells expected to be brought on line during the year in the Marcellus and 11 wells in North Louisiana. In the Marcellus, approximately half of the wells are planned to be drilled from existing pads in 2018.

Fourth quarter 2017 drilling expenditures of \$369 million funded the drilling of 53 (48 net) wells. Drilling expenditures for the year totaled \$1.18 billion, and Range drilled 177 (164 net) wells during the year. A 99% success rate was achieved. In addition, during 2017, \$62 million was spent on acreage

purchases, \$15 million on gas gathering systems and \$51 million on exploration expense.

Financial Discussion

Except for generally accepted accounting principles ("GAAP") reported amounts, specific expense categories exclude non-cash impairments, unrealized mark-to-market adjustment 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, processing and compression, production and ad valorem taxes, 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 2017

GAAP revenues for 2017 totaled \$2.6 billion (137% increase compared to 2016), GAAP net cash provided from operating activities including changes in working capital was \$816 million, compared to \$387 million in 2016, and GAAP earnings were \$333 million (\$1.34 per diluted share) versus a loss of \$521 million (\$2.75 per diluted share) in 2016. Full year 2017 results include a \$270 million impairment of unproved properties, reflecting expected North Louisiana lease expirations compared to \$30 million in 2016, a gain of \$24 million from asset sales compared to a loss of \$7 million in 2016, \$213 million in derivative gains due to decreases in future commodity prices compared to a \$261 million loss in the prior year and a \$51 million mark to market gain related to the deferred compensation plan compared to a \$19 million loss in the prior year. The reduction in the corporate tax rate from 35% to 21% under the Tax Cuts and Jobs Act of 2017 required a one-time revaluation of certain tax related assets and liabilities to reflect their value at the lower corporate tax rate. A one-time tax benefit was recorded related to the tax law changes in the amount of \$334 million.

Non-GAAP revenues for 2017 totaled \$2.4 billion, an increase of 41% compared to 2016 and cash flow from operations before changes in working capital, a non-GAAP measure, was \$916 million, compared to \$569 million in 2016. Adjusted net income comparable to analysts' estimates, a non-GAAP measure, was \$143 million (\$0.58 per diluted share), compared to \$4.9 million (\$0.03 per diluted share) in 2016.

Range announced its full year 2017 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates), which averaged \$2.99 per mcf, a 9% increase from the prior year. Additional detail on commodity price realizations can be found in the Supplemental Tables provided on the Company's website.

- Production and realized prices by each commodity for 2017 were: natural gas – 1,343 Mmcf per day (\$2.90 per mcf), NGLs – 97,834 barrels per day (\$14.88 per barrel) and crude oil and condensate – 13,115 barrels per day (\$49.49 per barrel).
- The 2017 average Company natural gas price including the impact of basis hedging was \$2.79 per mcf, or (\$0.31) per mcf below NYMEX which compares favorably to a (\$0.45) differential in the prior year. In addition, NYMEX natural gas financial hedges increased realizations \$0.11 per mcf for 2017.
- Pre-hedge NGL realizations improved to 33% of West Texas Intermediate ("WTI") in 2017, compared to 26% of WTI in 2016. Total NGL pricing per barrel including ethane and processing expenses after realized cash-settled hedging was \$14.88 per barrel compared to \$13.15 in the prior year. Hedging decreased NGL prices by \$2.04 per barrel in 2017 compared to an increase of \$1.71 per barrel in the prior year.
- Crude oil and condensate price realizations, before hedges, for the year averaged \$46.30 per barrel, or \$4.77 below WTI, compared to \$9.09 below WTI in the prior year. Hedging added \$3.19 per barrel in 2017, compared to hedge gains of \$13.22 per barrel in the prior year.

Range's total unit costs plus DD&A for 2017 continued to improve, decreasing by \$0.07 per mcf, or 3%, compared to the prior year, as shown below.

Expenses	Full Year 2017 (per mcf)	Full Year 2016 (per mcf)	Increase (Decrease)
Direct operating	\$ 0.18	\$ 0.17	6%
Transportation, gathering, processing and compression	1.04	1.00	4%
Production and ad valorem taxes	0.06	0.05	20%
General and administrative	0.21	0.23	(9%)
Interest expense	0.27	0.30	(10%)
Total cash unit costs	1.76	1.75	1%
Depletion, depreciation and amortization (DD&A)	0.85	0.93	(9%)
Total unit costs plus DD&A	\$ 2.61	\$ 2.68	(3%)

Fourth Quarter 2017

Fourth quarter 2017 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates) averaged \$3.01 per mcf, a 6% decrease from the prior-year quarter. Additional detail on commodity price realizations can be found in the Supplemental Tables provided on the Company's website.

- Production and realized prices by each commodity for fourth quarter 2017 were: natural gas – 1,444 Mmcf per day (\$2.84 per mcf), NGLs – 106,038 barrels per day (\$15.63 per barrel) and crude oil and condensate – 15,007 barrels per day (\$50.95 per barrel).
- The average Company natural gas price including the impact of basis hedging was \$2.59 per mcf, or (\$0.35) per mcf below NYMEX which compares to a (\$0.37) differential in the prior year quarter. In addition, NYMEX natural gas financial hedges increased realizations \$0.25 per mcf in fourth quarter 2017.
- Pre-hedge NGL realizations improved to 36% of WTI in fourth quarter 2017, compared to 29% of WTI in the previous year. Total NGL pricing per barrel, including ethane and processing expenses after realized cash-settled hedging decreased to \$15.63 for the fourth quarter compared to \$17.20 per barrel in the prior year. Hedging decreased NGL prices by \$4.06 per barrel in the fourth quarter compared to an increase of \$2.70 per barrel in the prior year.
- Crude oil and condensate price realizations, before realized hedges, for the fourth quarter averaged \$50.67 per barrel, or \$4.63 below WTI, compared to \$4.66 below WTI in the prior year. Hedging added \$0.27 per barrel compared to hedge gains of \$16.69 in the prior year.

Range's total unit costs plus DD&A in fourth quarter 2017 were 2% lower than the previous year quarter. Operating expenses increased due to workover expenses in north Louisiana. Increased transportation expenses were partially offset by higher realized prices, as products were moved to more favorable markets.

Expenses	4Q 2017 (per mcf)	4Q 2016 (per mcf)	Increase (Decrease)
Direct operating	\$ 0.19	\$ 0.17	12%
Transportation, gathering, processing and compression	1.00	0.96	4%
Production and ad valorem taxes	0.06	0.04	50%
General and administrative	0.21	0.26	(19%)
Interest expense	0.26	0.27	(4%)
Total cash unit costs	1.72	1.70	1%
Depletion, depreciation and amortization (DD&A)	0.82	0.88	(7%)
Total unit costs plus DD&A	\$ 2.54	\$ 2.58	(2%)

Operational Discussion

Range previously updated its investor presentation with economic calculations and type curves for the Marcellus and North Louisiana. Please see www.rangeresources.com under the Investors tab, "Company Presentations" area, for the presentation entitled, "Company Presentation – February 27, 2018"

The table below summarizes 2017 activity and estimates for 2018 regarding the number of wells to sales and average lateral lengths for each area. Updated well costs and EUR's by area can be found in the updated company presentation. Consistent with the prior year, updated type curves reflect expected flow restrictions that result from infrastructure and facility design constraints. As a result, early production from prolific wells is often constrained, resulting in flatter decline curves, and is reflected in the type curves. As seen in the presentation slides, Marcellus wells turned in line ("TIL") over the past four years in the southwest Pennsylvania wet and dry areas continue to perform in line with type curve expectations. In the super-rich area, the 2018 type curve was increased by approximately 8%, reflecting improved production performance. These results demonstrate the quality of acreage as the Company continues development across its core position in southwest Pennsylvania.

	Wells TIL		Planned Wells TIL	
	in 2017	Average 2017 Lateral Length	in 2018	Expected Average 2018 Lateral Length
SW PA Super-Rich	26	8,713 ft.	15	11,550 ft.
SW PA Wet	42	8,961 ft.	42	9,550 ft.
SW PA Dry	41	9,513 ft.	43	9,830 ft.
Total Appalachia	109		100	
Total N. LA.	58	6,881 ft.	11	7,500 ft.
Total	167		111	

Appalachia Division

Production for the fourth quarter of 2017 averaged approximately 1,799 net Mmcf per day from the Appalachia division, a 27% increase over the prior year. Included in this amount was over 100,000 barrels per day of liquids production, making Range one of the largest NGL producers in the U.S. among independent E&P companies. The southwest area of the division averaged 1,657 net Mmcf per day during the quarter, a 34% increase over

the prior year. This growth timed nicely with the Company's pipeline capacity additions. This was achieved through continued operational improvements and exceptional well results across Range's acreage position. The northeast area of the division averaged 126 net Mmcf per day during the fourth quarter.

The division brought on line 42 wells in the fourth quarter, one in the super-rich area, 17 in the wet area and 24 in the dry area. The division expects to run five rigs in 2018.

Some noteworthy results from the fourth quarter include:

- A five-well pad in the dry area that produced at a 24-hour IP rate of 36.1 Mmcfe per day per well completed with average lateral lengths of 14,400 feet and 73 stages per well
- A five-well pad in the wet area that produced at a 24-hour IP rate of 36.7 Mmcfe per day (including 2,814 NGL bbls per day) per well was completed with average lateral lengths of 13,600 feet and 68 stages per well
- A four-well pad in the super rich area (3 wells in 3Q17 and 1 well in 4Q17) that produced at a 24-hour IP rate of 40.3 Mmcfe per day (2,880 bbls NGLs and 1,707 bbls condensate per day) per well completed with average lateral lengths of 9,800 feet and 49 stages per well

North Louisiana

Production for the division in the fourth quarter of 2017 averaged approximately 348 net Mmcfe per day.

The division expects to turn in line 11 wells in 2018. The division will run one rig in 2018 as the team monitors results from 2017, while incorporating additional seismic data processed at the end of 2017. Production in North Louisiana is expected to decline through 2018, then remain relatively flat through the remainder of the previously announced five-year outlook.

Marketing and Transportation

In late 2017 and early 2018, two additional natural gas pipeline projects came on line for which Range has contracted for capacity, moving Marcellus gas from southwest Pennsylvania to favorable Gulf Coast markets. Enbridge's TETCO Adair Southwest project commenced service during the fourth quarter and TransCanada's Leach and Rayne Xpress project commenced full service in January. As a result of slight project delays, Range's fourth quarter transportation expense was better than expected. This was somewhat offset by higher natural gas differentials as more natural gas was sold locally. Energy Transfer's Rover project (phase 2) is expected to reach full completion in second quarter 2018, and is the last major natural gas transportation project for which Range has contracted for capacity. Once all of the projects are fully in service, approximately 90% of Range's 2018 gas price exposure is expected to be in favorable markets. Importantly, these additions to Range's transportation portfolio reduce basis volatility, especially during seasonally weak months, and should increase the predictability of Range's corporate natural gas differential going forward.

Financial Position and Liquidity

At December 31, 2017, Range had total debt outstanding of \$4.1 billion, before debt issuance costs, consisting of \$2.9 billion in senior notes, \$1.2 billion in bank debt and \$49 million in senior subordinated notes. Net debt outstanding, after unamortized debt issuance costs and premiums, equaled \$4.1 billion.

At December 31, 2017, Range's bank facility had a borrowing base of \$3.0 billion, and bank commitments of \$2.0 billion, with an outstanding balance of \$1.2 billion and undrawn letters of credit of \$281 million, leaving \$508 million of borrowing capacity available under the commitment amount.

Guidance – 2018

Production per day Guidance

Production for the first quarter of 2018 is expected to be approximately 2.18 Bcfe per day.

Production for the full year 2018 is expected to average approximately 2.23 Bcfe per day. This equates to a year-over-year growth rate of approximately 11%.

1Q 2018 Expense Guidance

Direct operating expense:	\$0.18 - \$0.19 per mcfe
Transportation, gathering, processing and compression expense:	\$1.04 - \$1.08 per mcfe
Production tax expense:	\$0.05 - \$0.07 per mcfe
Exploration expense:	\$7.0 - \$10.0 million
Unproved property impairment expense:	\$13.0 - \$15.0 million
G&A expense:	\$0.21 - \$0.23 per mcfe
Interest expense:	\$0.26 - \$0.28 per mcfe
DD&A expense:	\$0.82 - \$0.85 per mcfe
Net brokered gas marketing expense:	~\$2.0 million

1Q 2018 Natural gas price differentials

NYMEX plus \$0.11

Based on current market pricing indications, Range expects to receive the following pre-hedge differentials for its production in 2018.

Natural Gas: NYMEX minus \$0.15

Natural Gas Liquids (including ethane):
Oil/Condensate:

28% - 32% of WTI
WTI minus \$5.00 to 6.00

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 70% of its expected 2018 natural gas production hedged at a weighted average floor price of \$3.09 per mcf. Similarly, Range has hedged over 70% of its 2018 projected crude oil production at a floor price of \$53.30 and approximately 50% 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.

Range has also hedged Marcellus and other basis differentials to limit volatility between NYMEX and regional prices. The fair value of the basis hedges as of December 31, 2017 was a loss of \$7.8 million, compared to a gain of \$11.8 million at December 31, 2016.

Conference Call Information

A conference call to review the financial results is scheduled on Wednesday, February 28 at 9:00 a.m. ET. To participate in the call, please dial 866-900-7525 and provide conference code 7649028 about 10 minutes prior to the scheduled start time.

A simultaneous webcast of the call may be accessed at www.rangeresources.com. The webcast will be archived for replay on the Company's website until March 28.

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 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, processing 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, processing 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, processing and compression expense which historically were reported as natural gas, NGLs and oil sales. This information is intended 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 GAAP financial statements included in the Company's Annual Report on Form 10-K. 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.

Finding and development cost per unit is a non-GAAP metric used in the exploration and production industry by companies, investors and analysts. Drill-bit development cost per mcf is based on estimated and unaudited drilling, development and exploration costs incurred divided by the total of reserve additions, performance and price revisions. These calculations do not include the future development costs required for the development of proved undeveloped reserves. This reserves metric may not be comparable to similarly titled measurements used by other companies. 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.

We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax

amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and security analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

RANGE RESOURCES CORPORATION (NYSE:RRC) is a leading U.S. independent oil and natural gas producer with operations focused in stacked-pay projects in the Appalachian Basin and North Louisiana. 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 www.rangeresources.com.

Included within are certain "forward-looking statements" within the meaning of the federal securities laws, including the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 that are not limited to historical facts, but reflect Range's current beliefs, expectations or intentions regarding future events. Words such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "outlook," "estimate," "predict," "potential," "pursue," "target," "continue," and similar expressions are intended to identify such forward-looking statements.

All statements, except for statements of historical fact, made within regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future well costs, expected asset sales, well productivity, future liquidity and financial resilience, anticipated exports and related financial impact, NGL market supply and demand, improving commodity fundamentals and pricing, future capital efficiencies, future shareholder value, emerging plays, capital spending, anticipated drilling and completion activity, acreage prospectivity, expected pipeline utilization and future guidance information are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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. Further information on risks and uncertainties is available in Range's filings with the Securities and Exchange Commission (SEC), including its most recent Annual Report on Form 10-K. Unless required by law, Range undertakes no obligation to publicly update or revise any forward-looking statements to reflect circumstances or events after the date they are made.

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 its probable and possible reserves in its filings with the SEC. Range uses certain broader terms such as "resource potential," "unrisked resource potential," "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 on the SEC's website at www.sec.gov or by calling the SEC at 1-800-SEC-0330.

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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-K
(Unaudited, in thousands, except per share data)

	Three Months Ended December			Twelve Months Ended December		
	2017	2016	%	2017	2016	%
Revenues and other income:						
Natural gas, NGLs and oil sales (a)	\$ 603,159	\$ 458,645		\$ 2,176,287	\$ 1,197,215	
Derivative fair value income/(loss)	25,024	(250,057)		213,350	(261,391)	
Brokered natural gas, marketing and other (b)	50,732	44,774		219,474	163,219	
ARO settlement (loss) gain (b)	(17)	54		47	40	
Other (b)	134	106		1,872	856	
Total revenues and other income	<u>679,032</u>	<u>253,522</u>	168 %	<u>2,611,030</u>	<u>1,099,939</u>	137 %
Costs and expenses:						
Direct operating	37,424	29,755		132,192	95,086	
Direct operating – non-cash stock-based compensation (c)	497	521		2,060	2,302	
Transportation, gathering, processing and compression	200,300	164,338		761,183	565,209	
Production and ad valorem taxes	11,757	6,790		42,882	25,443	
Brokered natural gas and marketing	50,734	46,095		218,874	166,851	
Brokered natural gas and marketing – non-cash stock-based compensation (c)	397	376		1,437	1,725	
Exploration	6,747	13,055		50,920	30,027	
Exploration – non-cash stock-based compensation (c)	1,146	629		2,742	2,298	
Abandonment and impairment of unproved properties	217,544	6,307		269,725	30,076	
General and administrative	41,167	44,285		150,786	132,104	
General and administrative – non-cash stock-based compensation (c)	39,717	11,611		74,873	49,293	
General and administrative – lawsuit settlements	(831)	1,131		6,197	2,575	
General and administrative – bad debt expense	500	—		1,550	800	
Memorial merger expenses	—	813		—	37,225	
Termination costs	(278)	(822)		2,106	(519)	
Termination costs – non-cash stock-based compensation (c)	(1)	—		1,664	—	
Deferred compensation plan (d)	(14,077)	(11,013)		(50,915)	19,153	
Interest expense	51,473	46,749		195,679	168,213	
Depletion, depreciation and amortization	162,918	149,662		624,992	524,102	
Impairment of proved properties and other assets	—	—		63,679	43,040	
(Gain) loss on sale of assets	(207)	(470)		(23,716)	7,074	
Total costs and expenses	<u>806,927</u>	<u>509,812</u>	58 %	<u>2,528,910</u>	<u>1,902,077</u>	33 %

(Loss) income before income taxes	(127,895)	(256,290)	50 %	82,120	(802,138)	110 %
Income taxes:						
Current	17	98		17	98	
Deferred	(349,097)	(95,679)		(251,043)	(280,848)	
	<u>(349,080)</u>	<u>(95,581)</u>		<u>(251,026)</u>	<u>(280,750)</u>	
Net income (loss)	<u>\$ 221,185</u>	<u>\$ (160,709)</u>	238 %	<u>\$ 333,146</u>	<u>\$ (521,388)</u>	164 %
Net Income (Loss) Per Common Share:						
Basic	<u>\$ 0.89</u>	<u>\$ (0.66)</u>		<u>\$ 1.34</u>	<u>\$ (2.75)</u>	
Diluted	<u>\$ 0.89</u>	<u>\$ (0.66)</u>		<u>\$ 1.34</u>	<u>\$ (2.75)</u>	

Weighted average common shares outstanding, as reported:

Basic	245,281	244,362	0 %	245,091	189,868	29 %
Diluted	245,537	244,362	0 %	245,458	189,868	29 %

(a) See separate natural gas, NGLs and oil sales information table.

(b) Included in Brokered natural gas, marketing and other revenues in the 10-K.

(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-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, 2017	December 31, 2016
	(Audited)	(Audited)
Assets		
Current assets	\$ 370,627	\$ 268,605
Derivative assets	58,880	13,483
Goodwill	1,641,197	1,654,292
Natural gas and oil properties, successful efforts method	9,566,737	9,256,337
Transportation and field assets	14,666	16,873
Other	76,734	72,655
	<u>\$ 11,728,841</u>	<u>\$ 11,282,245</u>
Liabilities and Stockholders' Equity		
Current liabilities	\$ 704,913	\$ 530,373
Asset retirement obligations	6,327	7,271
Derivative liabilities	44,233	165,009
Bank debt	1,208,467	876,428
Senior notes	2,851,754	2,848,591
Senior subordinated notes	48,585	48,498
Total debt	<u>4,108,806</u>	<u>3,773,517</u>
Deferred tax liability	693,356	943,343
Derivative liabilities	9,789	24,491
Deferred compensation liability	101,102	119,231
Asset retirement obligations and other liabilities	286,043	310,642

Common stock and retained earnings	5,776,203	5,409,577
Other comprehensive loss	(1,332)	—
Common stock held in treasury stock	(599)	(1,209)
Total stockholders' equity	<u>5,774,272</u>	<u>5,408,368</u>
	<u>\$ 11,728,841</u>	<u>\$ 11,282,245</u>

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,		
	2017	2016	%	2017	2016	%
Total revenues and other income, as reported	\$ 679,032	\$ 253,522	168 %	\$ 2,611,030	\$ 1,099,939	137 %
Adjustment for certain special items:						
Total change in fair value related to derivatives prior to settlement (gain) loss	(27,969)	336,736		(200,233)	608,727	
ARO settlement (gain) loss	17	(54)		(47)	(40)	
Total revenues, as adjusted, non-GAAP	<u>\$ 651,080</u>	<u>\$ 590,204</u>	10 %	<u>\$ 2,410,750</u>	<u>\$ 1,708,626</u>	41 %

RANGE RESOURCES CORPORATION

CASH FLOWS FROM OPERATING ACTIVITIES

(Unaudited in thousands)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Net income (loss)	\$ 221,185	\$ (160,709)	\$ 333,146	\$ (521,388)
Adjustments to reconcile net cash provided from continuing operations:				
Deferred income taxes	(349,097)	(95,679)	(251,043)	(280,848)
Depletion, depreciation, amortization and impairment	162,918	149,662	688,671	567,142
Exploration dry hole costs	6	16	9,172	18
Abandonment and impairment of unproved properties	217,544	6,307	269,725	30,076
Derivative fair value income (loss)	(25,024)	250,057	(213,350)	261,391
Cash settlements on derivative financial instruments that do not qualify for hedge				
Accounting	(2,945)	86,679	13,117	347,336
Allowance for bad debts	500	—	1,550	800
Amortization of deferred issuance costs, loss on extinguishment of debt, and other	1,261	1,787	5,445	7,170
Deferred and stock-based compensation	26,769	1,996	30,706	74,685
(Gain) loss on sale of assets and other	(207)	(470)	(23,716)	7,074
Changes in working capital:				
Accounts receivable	(63,172)	(52,571)	(102,866)	(20,586)
Inventory and other	(1,475)	6,996	(2,979)	6,220
Accounts payable	1,197	14,009	45,912	(27,259)
Accrued liabilities and other	26,262	(26,849)	12,764	(64,763)
Net changes in working capital	<u>(37,188)</u>	<u>(58,415)</u>	<u>(47,169)</u>	<u>(106,388)</u>

Net cash provided from operating activities	<u>\$ 215,722</u>	<u>\$ 181,231</u>	<u>\$ 816,254</u>	<u>\$ 387,068</u>
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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,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Net cash provided from operating activities, as reported	\$ 215,722	\$ 181,231	\$ 816,254	\$ 387,068
Net changes in working capital	37,188	58,415	47,169	106,388
Exploration expense	6,230	13,039	41,237	30,009
Memorial merger expenses	—	813	—	37,225
Lawsuit settlements	(831)	1,131	6,197	2,575
Cash paid to exchange senior subordinated notes	—	—	—	6,600
Termination costs	(278)	(822)	2,106	(519)
Non-cash compensation adjustment	2,021	56	3,403	19
Cash flow from operations before changes in working capital – non-GAAP measure	<u>\$ 260,052</u>	<u>\$ 253,863</u>	<u>\$ 916,366</u>	<u>\$ 569,365</u>

ADJUSTED WEIGHTED AVERAGE SHARES OUTSTANDING

(Unaudited, in thousands)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Basic:				
Weighted average shares outstanding	248,140	247,161	247,882	192,661
Stock held by deferred compensation plan	(2,859)	(2,799)	(2,791)	(2,793)
Adjusted basic	<u>245,281</u>	<u>244,362</u>	<u>245,091</u>	<u>189,868</u>
Dilutive:				
Weighted average shares outstanding	248,140	247,161	247,882	192,661
Dilutive stock options under treasury method	(2,603)	(2,799)	(2,424)	(2,793)
Adjusted dilutive	<u>245,537</u>	<u>244,362</u>	<u>245,458</u>	<u>189,868</u>

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, a non-GAAP measure

(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2017	2016	%	2017	2016	%
Natural gas, NGL and oil sales components:						
Natural gas sales	\$ 340,965	\$ 289,790		\$ 1,349,965	\$ 753,888	
NGL sales	192,232	119,585		604,672	318,462	
Oil sales	69,962	49,270		221,650	124,865	
Total oil and gas sales, as reported	<u>\$ 603,159</u>	<u>\$ 458,645</u>	32 %	<u>\$ 2,176,287</u>	<u>\$ 1,197,215</u>	82 %
Derivative fair value income (loss), as reported:	\$ 25,024	\$ (250,057)		\$ 213,350	\$ (261,391)	
Cash settlements on derivative financial instruments – (gain) loss:						
Natural gas	(36,412)	(46,015)		(71,059)	(252,000)	
NGLs	39,733	(22,231)		73,192	(47,626)	
Crude Oil	(376)	(18,433)		(15,250)	(47,710)	
Total change in fair value related to derivatives prior to settlement, a non-GAAP measure	<u>\$ 27,969</u>	<u>\$ (336,736)</u>		<u>\$ 200,233</u>	<u>\$ (608,727)</u>	
Transportation, gathering, processing and compression components:						
Natural gas	\$ 141,902	\$ 114,854		\$ 526,671	\$ 403,209	
NGLs	58,398	49,484		234,512	162,000	
Total transportation, gathering, processing and compression, as reported	<u>\$ 200,300</u>	<u>\$ 164,338</u>		<u>\$ 761,183</u>	<u>\$ 565,209</u>	
Natural gas, NGL and oil sales, including cash-settled derivatives: (c)						
Natural gas sales	\$ 377,377	\$ 335,805		\$ 1,421,024	\$ 1,005,888	
NGL sales	152,499	141,816		531,480	366,088	
Oil sales	70,338	67,703		236,900	172,575	
Total	<u>\$ 600,214</u>	<u>\$ 545,324</u>	10 %	<u>\$ 2,189,404</u>	<u>\$ 1,544,551</u>	42 %
Production of oil and gas during the periods (a):						
Natural gas (mcf)	132,864,354	114,480,336	16 %	490,253,467	375,811,462	30 %
NGL (bbl)	9,755,481	8,245,792	18 %	35,709,254	27,825,635	28 %
Oil (bbl)	1,380,649	1,104,414	25 %	4,787,022	3,609,171	33 %
Gas equivalent (mcf) (b)	199,681,134	170,581,572	17 %	733,231,123	564,420,298	30 %
Production of oil and gas – average per day (a):						
Natural gas (mcf)	1,444,178	1,244,351	16 %	1,343,160	1,026,807	31 %
NGL (bbl)	106,038	89,628	18 %	97,834	76,026	29 %
Oil (bbl)	15,007	12,005	25 %	13,115	9,861	33 %
Gas equivalent (mcf) (b)	2,170,447	1,854,148	17 %	2,008,852	1,542,132	30 %
Average prices, including cash-settled hedges that qualify for hedge accounting before third party transportation costs:						
Natural gas (mcf)	\$ 2.57	\$ 2.53	1 %	\$ 2.75	\$ 2.01	37 %
NGL (bbl)	\$ 19.71	\$ 14.50	36 %	\$ 16.93	\$ 11.44	48 %
Oil (bbl)	\$ 50.67	\$ 44.61	14 %	\$ 46.30	\$ 34.60	34 %

Gas equivalent (mcf) (b)	\$	3.02	\$	2.69	12%	\$	2.97	\$	2.12	40%
Average prices, including cash-settled hedges and derivatives before third party transportation costs: (c)										
Natural gas (mcf)	\$	2.84	\$	2.93	-3%	\$	2.90	\$	2.68	8%
NGL (bbl)	\$	15.63	\$	17.20	-9%	\$	14.88	\$	13.16	13%
Oil (bbl)	\$	50.95	\$	61.30	-17%	\$	49.49	\$	47.82	3%
Gas equivalent (mcf) (b)	\$	3.01	\$	3.20	-6%	\$	2.99	\$	2.74	9%
Average prices, including cash-settled hedges and derivatives: (d)										
Natural gas (mcf)	\$	1.77	\$	1.93	-8%	\$	1.82	\$	1.60	14%
NGL (bbl)	\$	9.65	\$	11.20	-14%	\$	8.32	\$	7.33	13%
Oil (bbl)	\$	50.95	\$	61.30	-17%	\$	49.49	\$	47.82	3%
Gas equivalent (mcf) (b)	\$	2.00	\$	2.23	-10%	\$	1.95	\$	1.74	12%
Transportation, gathering and compression expense per mcf	\$	1.00	\$	0.96	4%	\$	1.04	\$	1.00	4%

(a) Represents volumes sold regardless of when produced.

(b) Oil and NGLs are converted at the rate of one barrel equals six mcf 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, processing and compression costs.

RANGE RESOURCES CORPORATION

RECONCILIATION OF INCOME BEFORE INCOME TAXES AS REPORTED TO INCOME 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,		
	2017	2016	%	2017	2016	%
(Loss) income from operations before income taxes, as reported	\$ (127,895)	\$ (256,290)	50%	\$ 82,120	\$ (802,138)	110%
Adjustment for certain special items:						
Loss (gain) on sale of assets	(207)	(470)		(23,716)	7,074	
(Gain) loss on ARO settlements	17	(54)		(47)	(40)	
Change in fair value related to derivatives prior to settlement	(27,969)	336,736		(200,233)	608,727	
Abandonment and impairment of unproved properties	217,544	6,307		269,725	30,076	
Impairment of proved property	—	—		63,679	43,040	
Memorial merger expenses	—	813		—	37,225	
Lawsuit settlements	(831)	1,131		6,197	2,575	
Fees paid to exchange senior subordinated notes	—	—		—	6,600	
Termination costs	(278)	(822)		2,106	(519)	
Termination costs – non-cash stock-based compensation	(1)	—		1,664	—	
Brokered natural gas and marketing – non-cash stock-based compensation	397	376		1,437	1,725	

Direct operating – non-cash stock-based compensation	497	521		2,060	2,302	
Exploration expenses – non-cash stock-based compensation	1,146	629		2,742	2,298	
General & administrative – non-cash stock-based compensation	39,717	11,611		74,873	49,293	
Deferred compensation plan – non-cash adjustment	(14,077)	(11,013)		(50,915)	19,153	
Income (loss) before income taxes, as adjusted	<u>88,060</u>	<u>89,475</u>	-2%	<u>231,692</u>	<u>7,391</u>	3,035%
Income tax expense, as adjusted						
Current	17	98		17	98	
Deferred (a)	<u>33,446</u>	<u>33,760</u>		<u>88,738</u>	<u>2,426</u>	
Net income (loss) excluding certain items, a non-GAAP measure	<u>\$ 54,597</u>	<u>\$ 55,618</u>	-2%	<u>\$ 142,937</u>	<u>\$ 4,867</u>	2,837%
Non-GAAP (loss) income per common share						
Basic	\$ 0.22	\$ 0.23	-4%	\$ 0.58	\$ 0.03	1,833%
Diluted	\$ 0.22	\$ 0.23	-4%	\$ 0.58	\$ 0.03	1,833%
Non-GAAP diluted shares outstanding, if dilutive	245,537	244,761		245,458	189,911	

(a) Deferred taxes for 2017 and 2016 are estimated to be approximately 38%.

RANGE RESOURCES CORPORATION

RECONCILIATION OF NET INCOME (LOSS), EXCLUDING CERTAIN ITEMS AND ADJUSTMENT EARNINGS PER SHARE, non-GAAP measures

(In thousands, except per share data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Net income (loss), as reported	\$ 221,185	\$ (160,709)	\$ 333,146	\$ (521,388)
Adjustment for certain special items:				
(Gain) loss on sale of assets	(207)	(470)	(23,716)	7,074
Loss (gain) on ARO settlements	17	(54)	(47)	(40)
Change in fair value related to derivatives prior to settlement	(27,969)	336,736	(200,233)	608,727
Impairment of proved property	—	—	63,679	43,040
Abandonment and impairment of unproved properties	217,544	6,307	269,725	30,076
MRD merger expenses	—	813	—	37,225
Fees paid to exchange senior subordinated notes	—	—	—	6,600
Lawsuit settlements	(831)	1,131	6,197	2,575
Termination costs	(278)	(822)	2,106	(519)
Non-cash stock-based compensation	41,756	13,137	82,776	55,618
Deferred compensation plan	(14,077)	(11,013)	(50,915)	19,153
Tax impact	<u>(382,543)</u>	<u>(129,439)</u>	<u>(339,781)</u>	<u>(283,274)</u>
Net income (loss) excluding certain items, a non-GAAP measure	<u>\$ 54,597</u>	<u>\$ 55,618</u>	<u>\$ 142,937</u>	<u>\$ 4,867</u>
Net income (loss) per diluted share, as reported	\$ 0.89	\$ (0.66)	\$ 1.34	\$ (2.75)

Adjustment for certain special items per diluted share:

(Gain) loss on sale of assets	(0.00)	(0.00)	(0.10)	0.04
Change in fair value related to derivatives prior to settlement	(0.11)	1.38	(0.82)	3.21
Impairment of proved property	—	—	0.26	0.23
Abandonment and impairment of unproved properties	0.89	0.03	1.10	0.16
MRD merger expenses	—	0.00	—	0.20
Fees paid to exchange senior subordinated notes	—	—	—	0.03
Lawsuit settlements	(0.00)	0.00	0.03	0.01
Termination costs	(0.00)	(0.00)	0.01	(0.00)
Non-cash stock-based compensation	0.17	0.05	0.34	0.29
Deferred compensation plan	(0.06)	(0.05)	(0.21)	0.10
Adjustment for rounding differences	0.01	—	0.01	0.01
Tax impact	(1.56)	(0.53)	(1.38)	(1.49)

Net income (loss) per diluted share, excluding certain items, a non-GAAP measure

\$	<u>0.22</u>	\$	<u>0.23</u>	\$	<u>0.58</u>	\$	<u>0.03</u>
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Adjusted earnings (loss) per share, a non-GAAP measure:

Basic	\$	0.22	\$	0.23	\$	0.58	\$	0.03
Diluted	\$	0.22	\$	0.23	\$	0.58	\$	0.03

RANGE RESOURCES CORPORATION**RECONCILIATION OF CASH MARGIN PER MCFE, a non-GAAP measure**

(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Revenues				
Natural gas, NGL and oil sales, as reported	\$ 603,159	\$ 458,645	\$ 2,176,287	\$ 1,197,215
Derivative fair value income (loss), as reported	25,024	(250,057)	213,350	(261,391)
Less non-cash fair value (gain) loss	(27,969)	336,736	(200,233)	608,727
Brokered natural gas and marketing and other, as reported	50,849	44,934	221,393	164,115
Less ARO settlement and other (gains) losses	(117)	(160)	(1,919)	(896)
Cash revenue applicable to production	<u>650,946</u>	<u>590,098</u>	<u>2,408,878</u>	<u>1,707,770</u>
Expenses				
Direct operating, as reported	37,921	30,276	134,252	97,388
Less direct operating stock-based compensation	(497)	(521)	(2,060)	(2,302)
Transportation, gathering and compression, as reported	200,300	164,338	761,183	565,209
Production and ad valorem taxes, as reported	11,757	6,790	42,882	25,443
Brokered natural gas and marketing, as reported	51,131	46,471	220,311	168,576
Less brokered natural gas and marketing stock-based compensation	(397)	(376)	(1,437)	(1,725)
General and administrative, as reported	80,553	57,027	233,406	184,772
Less G&A stock-based compensation	(39,717)	(11,611)	(74,873)	(49,293)
Less lawsuit settlements	831	(1,131)	(6,197)	(2,575)
Interest expense, as reported	<u>51,473</u>	<u>46,749</u>	<u>195,679</u>	<u>168,213</u>
Cash expenses	<u>393,355</u>	<u>338,012</u>	<u>1,503,146</u>	<u>1,153,706</u>

Cash margin, a non-GAAP measure	<u>\$ 257,591</u>	<u>\$ 252,086</u>	<u>\$ 905,732</u>	<u>\$ 554,064</u>
Mmcfe produced during period	199,681	170,581	733,231	564,420
Cash margin per mcfe	<u>\$ 1.29</u>	<u>\$ 1.48</u>	<u>\$ 1.24</u>	<u>\$ 0.98</u>

RECONCILIATION OF INCOME (LOSS) BEFORE INCOME TAXES TO CASH MARGIN

(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	<u>2017</u>	<u>2016</u>	<u>2017</u>	<u>2016</u>
Income (loss) before income taxes, as reported	\$ (127,895)	\$ (256,290)	\$ 82,120	\$ (802,138)
Adjustments to reconcile income (loss) before income taxes to cash margin:				
ARO settlements and other (gains) losses	(117)	(160)	(1,919)	(896)
Derivative fair value (income) loss	(25,024)	250,057	(213,350)	261,391
Net cash receipts on derivative settlements	(2,945)	86,679	13,117	347,336
Exploration expense	6,747	13,055	50,920	30,027
Lawsuit settlements	(831)	1,131	6,197	2,575
MRD merger expenses	—	813	—	37,225
Termination costs	(278)	(822)	2,106	(519)
Deferred compensation plan	(14,077)	(11,013)	(50,915)	19,153
Stock-based compensation (direct operating, brokered natural gas and marketing, general and administrative and termination costs)	41,756	13,137	82,776	55,618
Depletion, depreciation and amortization	162,918	149,662	624,992	524,102
(Gain) loss on sale of assets	(207)	(470)	(23,716)	7,074
Impairment of proved property and other assets	—	—	63,679	43,040
Abandonment and impairment of unproved properties	217,544	6,307	269,725	30,076
Cash margin, a non-GAAP measure	<u>\$ 257,591</u>	<u>\$ 252,086</u>	<u>\$ 905,732</u>	<u>\$ 554,064</u>

RANGE RESOURCES CORPORATION

HEDGING POSITION AS OF FEBRUARY 15, 2018 – (Unaudited)

	<u>Daily Volume</u>	<u>Hedge Price</u>
Gas ¹		
1Q 2018 Collars	60,000 Mmbtu	\$3.40 x \$3.76
1Q 2018 Swaps	1,100,778 Mmbtu	\$3.41
2Q 2018 Swaps	1,110,000 Mmbtu	\$2.98
3Q 2018 Swaps	1,110,000 Mmbtu	\$2.98
4Q 2018 Swaps	1,083,478 Mmbtu	\$2.98
2019 Swaps	237,329 Mmbtu	\$2.88
Oil		
1Q 2018 Swaps	9,750 bbls	\$53.42
2Q 2018 Swaps	9,250 bbls	\$53.35

3Q 2018 Swaps	8,500 bbls	\$53.20
4Q 2018 Swaps	8,500 bbls	\$53.20
2019 Swaps	5,622 bbls	\$53.49

C2 Ethane

1H 2018 Swaps	250 bbls	\$0.29/gallon
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C3 Propane ²

1Q 2018 Collars	2,000 bbls	\$0.90 x \$1.05 /gallon
1Q 2018 Swaps	14,250 bbls	\$0.70/gallon
2Q 2018 Swaps	11,960 bbls	\$0.66/gallon
3Q 2018 Swaps	8,918 bbls	\$0.62/gallon
4Q 2018 Swaps	7,918 bbls	\$0.59/gallon

C4 Normal Butane

1Q 2018 Swaps	5,500 bbls	\$0.82/gallon
2Q 2018 Swaps	4,500 bbls	\$0.81/gallon
3Q 2018 Swaps	4,250 bbls	\$0.81/gallon
4Q 2018 Swaps	4,250 bbls	\$0.81/gallon

C5 Natural Gasoline

1Q 2018 Swaps	5,917 bbls	\$1.19/gallon
2Q 2018 Swaps	5,159 bbls	\$1.22/gallon
3Q 2018 Swaps	4,902 bbls	\$1.21/gallon
4Q 2018 Swaps	4,652 bbls	\$1.21/gallon
1H 2019 Swaps	1,000 bbls	\$1.24/gallon

1. Range also sold call swaptions of 220,000 Mmbtu/d for April-December 2018 and 245,000 Mmbtu/d for calendar 2019 at average strike prices of \$2.87 and \$3.04 per Mmbtu, respectively
2. Swaps incorporate international propane hedges

SEE WEBSITE FOR OTHER SUPPLEMENTAL INFORMATION FOR THE PERIODS AND ADDITIONAL HEDGING DETAILS



Range Resources Corporation