

- **Second Quarter Production Increased 47% Year-Over-Year to 13.9 MBoe/d**
- **Substantially Increased Average Type Curve Estimated Ultimate Recovery and Enhanced Internal Rate of Return Outlook for Upper Hunton Wells on WEHLU Acreage**
- **Raised Production Guidance on Increased 2015 Capital Budget**

HOUSTON, Aug. 6, 2015 /CNW/ -- [Gastar Exploration Inc.](#) (NYSE MKT: GST) ("Gastar") today reported financial and operating results for the second quarter of 2015.

Net loss attributable to Gastar's common stockholders as reported for the second quarter of 2015 was \$118.0 million, or a loss of \$1.18 per share, which includes a \$10.1 million non-cash, pre-tax ceiling test impairment charge and a \$7.8 million loss resulting from the mark-to-market of outstanding hedge positions. Net income attributable to common stockholders was \$10.1 million, or a loss of \$0.13 per share. This compares to second quarter 2014 reported net income of \$2.0 million, or a loss of \$0.02 per share, which includes an \$8.6 million net benefit related to an arbitration settlement. Excluding the impact of a \$5.4 million loss resulting from the mark-to-market of outstanding hedge positions, second quarter 2014 adjusted net income was \$7.5 million, or \$0.12 per diluted share. (See the accompanying reconciliation of net (loss) income to adjusted EBITDA at the end of this news release.) Second quarter 2015 results compare to a first quarter 2015 net loss of \$3.0 million, or a loss of \$0.03 per share, which excludes a \$4.3 million gain resulting from the mark-to-market of outstanding hedge positions.

Adjusted earnings before interest, income taxes, depreciation, depletion and amortization ("adjusted EBITDA") for the second quarter of 2015 was \$29.4 million, compared to \$29.4 million in the second quarter of 2014, which includes the impact of an \$8.6 million net benefit related to an arbitration settlement, and compared to \$20.0 million in the first quarter of 2015. (See the accompanying reconciliation of net (loss) income to adjusted EBITDA, a non-GAAP measure, at the end of this news release.)

Revenues from oil, condensate, natural gas and natural gas liquids ("NGLs"), before the impact of hedging activities, were \$23.7 million in the second quarter of 2015, a 47% decline from \$44.8 million in the second quarter of 2014 and a decline of 2% from \$24.1 million in the first quarter of 2015. The reduction in revenues from the second quarter of 2014 was primarily the result of a 53% decrease in weighted average realized equivalent prices for oil and condensate, a \$1.0 million benefit related to an arbitration settlement in 2014, partially offset by a 47% increase in production. The slight decrease from the first quarter of 2015 was primarily the result of a 12% decline in equivalent product pricing partially offset by a 10% increase in average daily production.

Revenues from liquids (oil, condensate and NGLs) represented approximately 83% of total production revenues in the second quarter of 2015, compared to 83% in the second quarter of 2014 (excluding the benefit from the arbitration settlement mentioned above) and 72% during the first quarter of 2015. We have entered into derivative contracts covering approximately 70% of our natural gas production, 47% of our NGLs production and 31% of our oil and condensate production. Derivative contracts settled during the period resulted in a \$6.0 million increase in revenue for the second quarter of 2015, compared to a \$1.0 million decrease in the second quarter of 2014 and an increase in revenue of \$6.0 million for the first quarter of 2015. Second quarter 2015 hedge benefit was \$6.0 million, or 25% of total production revenues, compared to \$1.0 million, or 2% of total production revenues, in the second quarter of 2014, whereas in the second quarter of 2014, hedging reduced our Boe pricing by approximately 10%. We continue to hedge a portion of estimated future production, which is reported in our periodic filings with the U.S. Securities and Exchange Commission.

Average daily production for the second quarter of 2015 was 13,900 barrels of oil equivalent per day ("Boe/d") as compared to 9,500 Boe/d in the first quarter of 2015. Liquids as a percentage of total equivalent production volumes were 53% in the second quarter of 2015, compared to 53% in the second quarter of 2014 and 52% in the first quarter of 2015.

J. Russell Porter, Gastar's President and CEO, commented, "We are encouraged by the continued positive drilling results on our WEHLU wells. In the second quarter of 2015, we brought on production two wells in the upper Hunton formation, the Blair Farms 31-1H and the Easton 2-1H, both of which are producing at a production rate substantially above our previous type curve. With this continued demonstrated outperformance of our production operations, we have increased our estimated ultimate recovery (EUR) on our upper Hunton wells. WEHLU upper Hunton wells are now assigned an unproved undeveloped wells in this area, an increase of 35% from our previous estimate of 233 Mboe (74% oil). Due to the strong production results, we estimate \$3.3 million per 6,000 foot lateral well, we now estimate the internal rate of return (IRR), based on return on estimated drilling and completion costs, for the upper Hunton wells to be approximately 39%."

"We also continue to experience solid production results from our lower Hunton WEHLU drilled wells and have increased our unproved undeveloped wells to 316 Mboe (87% oil). Based on NYMEX commodity price curves and estimated well costs of \$5.5 million per 6,000 foot lateral well, we estimate the IRR for these wells to be approximately 39%."

"Due to our encouraging WEHLU drilling results and enhanced liquidity following the recent sale of non-core acreage in Oklahoma, we are increasing our total 2015 capital expenditure program. We are increasing our budgeted capital expenditures from \$103 million to \$120 million, which includes a Lime test on our Mid-Continent acreage, an additional lower Hunton WEHLU well and additional costs incurred to date in our non-operating areas. As a result of the additional capital, the mid-point of our projected 2015 full-year production has been increased 8% to 13.5 MBoe/d, representing a 32% increase from 10.2 MBoe/d in 2014. We are increasingly more enthusiastic about the potential of the STACK - Meramec Shale formation on our Mid-Continent acreage, particularly from wells being drilled by offset and nearby operators. Our plan is to drill and complete our first test by the end of 2015, which will be followed by the development of the play in 2016," said Porter.

The following table provides a summary of Gastar's production volumes and average commodity prices for the three and six months ended June 30, 2015.

For the Three Months Ended June 30, For the Six Months Ended

2015 2014 2015 2014

(In thousands, except per unit amounts)

Net Production:

Oil and condensate (MBbl)	369	207	736	410
Natural gas (MMcf)	3,575	2,680	6,870	5,750
NGLs (MBbl)	297	208	516	363
Total net production (MBoe)	1,262	861	2,397	1,733

Net Daily production:

Oil and condensate (MBbl/d)	4.1	2.3	4.1	2.3
Natural gas (MMcf/d)	39.3	29.5	38.0	31.8
NGLs (MBbl/d)	3.3	2.3	2.9	2.0
Total net daily production (MBoe/d)	13.9	9.5	13.2	9.6

Average sales price per unit⁽¹⁾:

Oil and condensate per Bbl, including impact of hedging activities ⁽²⁾	\$2.20	\$7.30	\$9.86	\$3.40
Oil and condensate per Bbl, excluding impact of hedging activities	\$7.68	\$2.84	\$4.76	\$7.70
Natural gas per Mcf, including impact of hedging activities ⁽²⁾	\$0.68	\$0.03	\$0.11	\$0.73
Natural gas per Mcf, excluding impact of hedging activities	\$1.10	\$0.52	\$0.55	\$0.32
NGLs per Bbl, including impact of hedging activities ⁽²⁾	\$4.97	\$1.92	\$6.72	\$9.00
NGLs per Bbl, excluding impact of hedging activities	\$0.34	\$6.88	\$0.29	\$3.60
Average sales price per Boe, including impact of hedging activities ⁽¹⁾⁽²⁾	\$3.54	\$5.67	\$4.96	\$8.20
Average sales price per Boe, excluding impact of hedging activities ⁽¹⁾	\$8.79	\$9.72	\$9.97	\$2.10

(1)	The three and six months ended June 30, 2014 exclude the benefit of a one-time revenue adjustment related to an arbitration settlement.
(2)	The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the periods presented.

Lease operating expenses ("LOE") were \$7.2 million in the second quarter of 2015, versus \$4.9 million in the second quarter of 2014 and \$6.0 million in the first quarter of 2015. Compared to the second quarter of 2014, LOE in the second quarter of 2015 increased \$2.3 million primarily due to one-time workover costs of \$1.3 million for production enhancement on five wells in our operated WEHLU acreage, \$449,000 in insurance expenses and an increase in costs as a result of higher production volumes. Compared to the first quarter of 2015, LOE was higher primarily due to approximately \$755,000 of higher expenses related to increased production volumes, water hauling costs for new wells in the Mid-Continent and the Appalachian Basin and costs for production enhancing electric submersible pumps in WEHLU coupled with \$455,000 of higher insurance expenses. LOE per Boe of production was \$5.74 in the second quarter of 2015 versus \$5.66 in the second quarter of 2014 and \$5.30 in the first quarter of 2015. Excluding workover costs as well as the impact of an arbitration settlement in 2014, LOE per Boe for second quarter of 2015 was \$4.64 compared to \$5.82 per Boe for the second quarter of 2014 and \$4.09 per Boe for the first quarter of 2015.

Depreciation, depletion and amortization expense ("DD&A") was \$16.1 million in the second quarter of 2015, up from \$10.3 million in the second quarter of 2014 and \$14.5 million in the first quarter of 2015. The year-over-year increase in DD&A expense was the result of 47% higher production volumes and a 7% increase in DD&A rate per Boe, primarily due to decreased

proved reserve volumes. The reserve volume reduction was due to lower economic limits and proved undeveloped reserves being less economically viable because of the reduced commodity price environment. DD&A increased sequentially due to higher production volumes. The DD&A rate per Boe for the second quarter of 2015 was \$12.74 compared to \$11.94 for the second quarter of 2014 and \$12.75 in the first quarter of 2015.

General and administrative ("G&A") expense was \$4.4 million in the second quarter of 2015 compared to \$3.9 million in the second quarter of 2014 and \$4.2 million in the first quarter of 2015. G&A expense in the second quarter of 2015 included \$1.2 million of non-cash stock-based compensation expense compared to \$1.0 million in the second quarter of 2014 and \$1.5 million in the first quarter of 2015. Excluding stock-based compensation expense, cash G&A expense increased to \$3.2 million in the second quarter of 2015 from \$2.9 million in the second quarter of 2014 and from \$2.7 million in the first quarter of 2015. This increase from the second quarter of 2014 was primarily due to higher legal costs.

Interest expense totaled \$6.9 million in the second quarter of 2015, which was flat compared to the second quarter of 2014 and down from \$7.6 million in the first quarter 2015. See "Liquidity" below for more information about available borrowings under our revolving credit facility.

Operations Review and Update

Mid-Continent

Net production from the Mid-Continent area increased to an average of 6,200 Boe/d in the second quarter of 2015, compared to 4,100 Boe/d in the second quarter of 2014 and 5,900 Boe/d in the first quarter of 2015. Second quarter 2015 Mid-Continent equivalent production consisted of approximately 54% oil, 26% natural gas and 20% NGLs.

On our WEHLU acreage, we completed three gross (2.9 net) operated wells during the second quarter of 2015, consisting of two upper and one lower Hunton completions. We currently have two rigs running within WEHLU and anticipate releasing both rigs before the end of the third quarter 2015 as we evaluate our WEHLU Hunton drilling results, monitor commodity prices and assess service costs. We plan to complete and bring on production a total of eight gross (7.9 net) operated wells on our WEHLU acreage in the third quarter of 2015, consisting of three upper Hunton and five lower Hunton completions, of which one upper and one lower Hunton completion will be located on the less drilled southern portion of our WEHLU acreage.

The table below shows wells brought on production or for which drilling operations have commenced since the beginning of 2015 within our operated acreage in the Hunton Limestone formation, all of which are located within the WEHLU acreage:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates ⁽¹⁾ BOE/d	% Oil
(BOE/d)				
Upper Hunton Completions				
Warsaw 33-2H	98.3%	4,900	615	260 63%
Blair Farms 31-1H	98.3%	6,500	509	353 83%
Easton 22-4H	98.3%	6,500	604	357 89%
Jetson 8-2H	98.3%	5,900	N/A	N/A N/A
Arcadia Farms 15-2H	98.3%	6,800	N/A	N/A N/A
O' Donnell 5-1H	98.3%	6,800	N/A	N/A N/A
Lower Hunton Completions				
Warsaw 33-3H	98.3%	5,800	663	250 62%
Easton 22-3H	98.3%	6,500	N/A	335 83%
Davis 9-2H	98.3%	6,800	N/A	N/A N/A
Davis 9-4H	98.3%	7,400	N/A	N/A N/A
Jetson 8-1H	98.3%	5,000	N/A	N/A N/A
Arcadia Farms 15-1CH	98.3%	6,800	N/A	N/A N/A
O'Donnell 5-2CH	98.3%	7,500	N/A	N/A N/A
Warsaw 33-1 ⁽³⁾	98.3%	N/A	59	27 47%

(1)	Represents highest daily gross Boe rate.
(2)	Represents gross cumulative production divided by actual producing days through July 19, 2015.
(3)	The Warsaw 33-1 is a commingled vertical pilot well completed in the upper, middle and lower Hunton zones.

Within our AMI acreage in the Mid-Continent, three gross (1.5 net) non-operated wells were placed on production during the second quarter of 2015, and one gross (0.5 net) non-operated well was successfully re-drilled to correct an initial horizontal casing collapse and is waiting on completion. Once the re-drilled well is completed, we currently have no plans to drill any additional Hunton wells on our AMI acreage. The table below shows wells brought on production or for which drilling operations have commenced since the beginning of 2015 within our original AMI in the Hunton Limestone formation (all of which are operated by a third-party):

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates ⁽¹⁾ (Boe/d)	Boe/d	% Oil
LB 1-1H	47.6%	4,400	791	242	65%
Hubbard 1-23H ⁽³⁾	57.0%	4,600	N/A	22	95%
Boss Hogg 1-14H	50.0%	4,400	129	61	68%
Bo 1-23H	43.8%	4,900	547	307	47%
The River 1-22H	39.7%	4,400	1,250	943	34%
Bigfoot 1-9H	47.4%	4,800	161	112	58%
Falcon 1-5H	51.5%	4,700	1,202	547	84%
Dorothy 1-12H	49.5%	5,000	N/A	17	78%
Polar Bear 1-20H	47.7%	4,400	403	180	87%
Unruh 1-34H ⁽⁴⁾	49.0%	4,900	N/A	N/A	N/A

(1) Represents highest daily gross Boe rate.

(2) Represents gross cumulative production divided by actual producing days through July 19, 2015.

(3) After payout working interest is 49.9%.

(4) Approximate gross costs to drill and complete includes costs to re-drill the well due to an initial horizontal casing collapse.

In the Mid-Continent, our net capital expenditures in the second quarter of 2015 totaled approximately \$27 million, resulting in year-to-date expenditures of \$55 million, including land costs of \$12 million. We anticipate spudding our first operated Meramec Shale well by September 2015 and, if successful, the well should be on production by late October 2015 at an estimated cost of \$6.5 million. Our total remaining 2015 capital expenditure budget in the Mid-Continent is approximately \$31 million, of which \$30 million has been allocated to drilling and completion.

Appalachian Basin

Net production from the Appalachian Basin area averaged 7,700 Boe/d in the second quarter of 2015 compared to 5,400 Boe/d for the second quarter of 2014 and 6,700 Boe/d in the first quarter of 2015. Year-over-year production volume increases were due to seven gross (3.5 net) Armstrong Marcellus Shale wells and three gross (1.5 net) Hansen Marcellus Shale wells that were brought on production in mid-to-late December 2014, three gross (1.5 net) Goudy Marcellus Shale wells that were brought online in March 2015 and five gross (2.5 net) wells added in the second quarter of 2015.

During the second quarter of 2015, two gross (1.0 net) Hoyt Marcellus Shale wells were brought on production in early April 2015 and two gross (1.0 net) Marcellus Shale wells and one gross (0.5 net) Utica/Point Pleasant well were brought on production on the Blake pad in May 2015. As previously stated, we have no additional wells budgeted to be drilled and completed in the Appalachian Basin for the remainder of 2015. We will continue to monitor the commodity pricing environment and services costs and will reconsider our drilling plans pending more favorable economic conditions in the basin.

Net capital expenditures in the Appalachian Basin for the second quarter of 2015 totaled approximately \$9 million, resulting in year-to-date expenditures of \$21 million. Our total remaining 2015 capital budget for the Appalachian Basin is approximately \$6 million, primarily for acquiring additional mineral rights in the area.

Liquidity

At June 30, 2015, we had approximately \$9.4 million in available cash and cash equivalents and \$105.0 million of availability under our \$200.0 million revolving credit facility borrowing base, or total available liquidity of \$114.4 million. Subsequent to the end of the second quarter 2015, we completed the sale of non-core Oklahoma assets for net proceeds of \$46.1 million resulting in pro forma total liquidity of \$160.5 million. We expect to fund our remaining 2015 capital program of approximately \$41.0 million through existing cash balances, internally generated cash flow from operating activities, borrowings under the revolving credit facility, property sales and possible capital markets transactions, or some combination thereof.

Guidance for the Third Quarter of 2015

We are updating our previously issued guidance for the full year 2015 and providing the following guidance for the third quarter of 2015:

Production	Third Quarter Full-Year	
	2015 ⁽¹⁾	2015 ⁽¹⁾
Net average daily (MBoe/d) ⁽²⁾	13.5 - 14.0	13.2 - 13.7
Liquids percentage	54% - 58%	52% - 56%
Cash Operating Expenses	Third Quarter Full-Year	
	2015	2015
Production taxes (% of production revenues)	3.9% - 4.3%	3.8% - 4.1%
Direct lease operating (\$/Boe)	\$4.50 - \$4.90	\$4.90 - \$5.20
Transportation, treating & gathering (\$/Boe)	\$0.49 - \$0.52	\$0.47 - \$0.50
Cash general & administrative (\$/Boe)	\$2.80 - \$3.20	\$2.60 - \$2.90

(1) Includes adjustment for Oklahoma non-core asset divestiture with property sale effective date of April 1, 2015.

(2) Based on equivalent of 6 thousand cubic feet (Mcf) of natural gas to one barrel of oil, condensate or NGLs.

Mid-Year 2015 Reserve Update

Gastar's mid-year 2015 total proved reserves declined by 10.7 MMBoe to 91.4 MMBoe, of which 38% is proved developed. The total proved reserve decrease of 10% from year-end 2014 was primarily attributable to a declining commodity price environment that has reduced proved reserve value and economic limits and has rendered some proved undeveloped well locations economically nonviable. Proved reserves at June 30, 2015 were composed of 29.3 million barrels of crude oil and condensate, 20.3 million barrels of NGLs and 250 billion cubic feet of natural gas. The pre-tax SEC-priced present value of future cash flows of these reserves, discounted at 10% ("PV-10") (a non-GAAP financial measure defined below in Information on Reserves and PV-10 Value), diminished by 46% to \$538.0 million as compared to year-end 2014 as a direct result of lower SEC prices. In accordance with SEC regulations, estimates of proved reserves as of June 30, 2015 were calculated using the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period July 1, 2014 through June 30, 2015. For oil volumes, the average West Texas Intermediate price utilized was \$71.68 per barrel, compared to \$94.99 per barrel for year-end 2014, and for natural gas volumes, the average Henry Hub price utilized was \$3.39 per million Btu (MMBtu), compared to \$4.35 per MMBtu for year-end 2014. These benchmark oil and natural gas prices were adjusted for energy content or quality, transportation and regional price differentials by area.

For a discussion of PV-10 and the standardized measure of future net cash flows, see "Information on Reserves and PV-10 Value."

Conference Call

Gastar has scheduled a conference call for 11:00 a.m. Eastern Time (10:00 a.m. Central Time) on Friday, August 7, 2015. Investors may participate in the call either by phone or audio webcast.

By Phone: Dial 1-412-902-0030 at least 10 minutes before the call. A telephone replay will be available through August 14, 2015 by dialing 1-201-612-7415 and using the conference ID: 13613121.

By Webcast: Visit the Investor Relations page of Gastar's website at www.gastar.com under "Events & Presentations." Please log on 15-20 minutes in advance to register and download any necessary software. A replay will be available shortly after the call.

For more information, please contact Donna Washburn at Dennard-Lascar Associates at 713-529-6600 or e-mail dwashburn@DennardLascar.com.

About Gastar Exploration

[Gastar Exploration Inc.](#) is an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and natural gas liquids in the United States. Gastar's principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. In Oklahoma, Gastar is developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal play and expects to test other prospective formations on the same acreage, including the Meramec Shale (middle Mississippi Lime) and the Woodford Shale, which Gastar refers to as the STACK Play. In West Virginia, Gastar is developing liquids-rich natural gas in the Marcellus Shale and has drilled and completed its first two successful dry gas Utica Shale/Point Pleasant wells on its acreage. For more information, visit Gastar's website at www.gastar.com.

Information on Reserves and PV-10 Value

At June 30, 2015, future cash inflows were computed using the 12-month unweighted arithmetic average of the first-day-of-the-month prices for natural gas and oil (the "benchmark base prices") adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials, relating to the Company's proved reserves. Benchmark base prices are held constant in accordance with SEC guidelines for the life of the wells but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression, and gathering fees and regional price differentials. The average benchmark base prices used in our June 30, 2015 SEC compliant reserves report are significantly above current market commodity prices.

PV-10 is a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our reserves prior to taking into account corporate future income taxes and our current tax structure. We further believe investors and creditors use PV-10 as a basis for comparison of the relative size of our reserves as compared with other companies.

The financial measure most directly comparable to PV-10 is the standardized measure of future net cash flows ("Standardized Measure"). We are not yet able to provide a reconciliation of PV-10 to Standardized Measure because the discounted future income taxes associated with our reserves is not yet calculable.

We use the term "EUR" or "estimated ultimate recovery" to describe potentially recoverable oil and gas hydrocarbon quantities that are not permitted to be used in filings with the SEC. EURs included in this release are estimated ultimate recoveries of quantities (i.e., production to date plus remaining estimated proved volumes) based on our most recent proved undeveloped estimates, although a portion of our drilling locations have been booked as proved undeveloped. We include these estimates to demonstrate what we believe to be the potential for future drilling and production on our properties. These estimates are by their nature much more speculative than estimates of proved reserves and would require a commitment for substantial capital spending over a significant number of years to implement recovery and book as proved reserves. Actual locations drilled and quantities that may be ultimately recovered from our properties may differ substantially, even if targeting the same formations. Commodities pricing will also affect EUR volumes. In addition, we have made no commitment to drill, and likely will not drill, all of the drilling locations which have been attributed to these quantities.

EUR data included herein remain subject to change as more well data is analyzed and, except as otherwise noted, are not reflective of proved undeveloped estimates. Ultimate recoveries will be dependent on numerous factors, including actual encountered geological conditions, the impact of future oil and gas pricing, exploration and development costs, and our future drilling decisions and budgets based upon our future evaluation of risk, returns and the availability of capital and, in many areas, the outcome of negotiation of drilling arrangements with holders of adjacent or fractional interest leases.

Internal rates of return, or IRR, estimates included in this release are included for illustrative purposes and reflect returns based upon our type curve production estimates and production pricing assumptions solely on our estimated drilling and completion expenditures for such wells which do not include other relevant costs such as land costs, geological and geophysical costs or allocated G&A costs. IRRs included herein are based upon NYMEX future commodity price curves as of July 31, 2015.

The Company's June 30, 2015 total proved reserves estimates were prepared by Wright & Company, Inc.

Forward-Looking Statements

This news release also includes "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. Forward looking statements give our current expectations, opinion, belief or forecasts of future events and performance. A statement identified by the use of forward looking words including "may," "expects," "projects," "anticipates," "plans," "believes," "estimate," "will," "should," and certain of the other foregoing statements may be deemed forward-looking statements. Although Gastar believes that the expectations reflected in such forward-looking statements are reasonable, these statements involve risks and uncertainties that may cause actual future activities and results to be materially different from those suggested or described in this news release. These include risks inherent in natural gas and oil drilling and production activities, including risks with respect to continued low or further declining prices for oil and natural gas that could cause Gastar to further delay or suspend planned drilling and completion operations or reduce production levels which would adversely impact cash flow; risks relating to the availability of capital to fund drilling operations that can be adversely affected by adverse drilling results, production declines and declines in natural gas and oil prices; risks regarding our ability to meet financial covenants under our indenture or credit agreements or the ability to obtain amendments or waivers to effect such compliance; risks of fire, explosion, blowouts, pipe failure, casing collapse, unusual or unexpected formation pressures, environmental hazards, and other operating and production risks, which may temporarily or permanently reduce production or cause initial production or test results to not be indicative of future well performance or delay the timing of sales or completion of drilling operations; delays in receipt of drilling permits; risks relating to unexpected adverse developments in the status of properties; borrowing base redeterminations by our banks; risks relating to the absence or delay in receipt of government approvals or third-party consents; risks relating to our ability to realize the anticipated benefits from acquired assets; and other risks described in Gastar's Annual Report on Form 10-K and other filings with the SEC, available at the SEC's website at www.sec.gov. Our actual sales production rates can vary considerably from tested initial production rates depending upon completion and production techniques and our primary areas of operations are subject to natural steep decline rates. By issuing forward looking statements based on current expectations, opinions, views or beliefs, Gastar has no obligation and, except as required by law, is not undertaking any obligation, to update or revise these statements or provide any other information relating to such statements.

Unless otherwise stated herein, equivalent volumes of production and reserves are based upon an energy equivalent ratio of six Mcf of natural gas to each barrel of liquids (oil, condensate and NGLs), which ratio is not reflective of relative value. Our NGLs are sold as part of our wet gas subject to an incremental NGLs pricing formula based upon a percentage of NGLs extracted from our wet gas production. Our reported production volumes reflect incremental post-processing NGLs volumes and residual gas volumes with which we are credited under our sales contracts.

Targeted expectations and guidance for 2015 are based upon the current revised 2015 capital expenditures budget, which may be subject to revision and reevaluation dependent upon future developments, including drilling results, availability of crews, supplies and production capacity, weather delays, and significant changes in commodities prices or drilling costs.

Contacts:

[Gastar Exploration Inc.](http://GastarExploration.com)

Michael A. Gerlich, Chief Financial Officer

713-739-1800 / mgerlich@gastar.com

Investor Relations Counsel:

Lisa Elliott, Dennard-Lascar Associates:

713-529-6600 / lelliott@DennardLascar.com

- Financial Tables Follow -

GASTAR EXPLORATION INC.		
CONSOLIDATED STATEMENTS OF OPERATIONS		
	For the Three Months Ended	
	June 30, 2015	June 30, 2014
	(in thousands, except per share amounts)	
REVENUES:		
Oil and condensate	\$ 17,584	\$ 17,584

Natural gas	3,950	1
NGLs	2,184	4
Total oil, condensate, natural gas and NGLs revenues	23,718	4
(Loss) gain on commodity derivatives contracts	(1,790)	(8)
Total revenues	21,928	3
EXPENSES:		
Production taxes	822	2
Lease operating expenses	7,242	4
Transportation, treating and gathering	542	2
Depreciation, depletion and amortization	16,080	1
Impairment of oil and natural gas properties	100,152	&
Accretion of asset retirement obligation	131	1
General and administrative expense	4,421	3
Total expenses	129,390	2
(LOSS) INCOME FROM OPERATIONS	(107,462)	1
OTHER INCOME (EXPENSE):		
Interest expense	(6,936)	(6)
Investment income and other	3	4
Foreign transaction loss	—	(4)
(LOSS) INCOME BEFORE PROVISION FOR INCOME TAXES	(114,395)	5
Provision for income taxes	—	&
NET (LOSS) INCOME	(114,395)	5
Dividends on preferred stock	(3,619)	(3)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	\$ (118,014)	\$
NET (LOSS) INCOME PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:		
Basic	\$ (1.52)	\$
Diluted	\$ (1.52)	\$
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:		
Basic	77,611,167	5
Diluted	77,611,167	6

GASTAR EXPLORATION INC.

CONSOLIDATED BALANCE SHEETS

	June 30, 2018
	(U.S. dollars in thousands)
	(in thousands)
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	\$ 16,300
Accounts receivable, net of allowance for doubtful accounts of \$0, respectively	16,300
Commodity derivative contracts	13,300
Prepaid expenses	68,000
Total current assets	39,900
PROPERTY, PLANT AND EQUIPMENT:	
Oil and natural gas properties, full cost method of accounting:	
Unproved properties, excluded from amortization	12,300
Proved properties	1,200
Total oil and natural gas properties	1,300
Furniture and equipment	3,000
Total property, plant and equipment	1,300
Accumulated depreciation, depletion and amortization	(6,000)
Total property, plant and equipment, net	64,000
OTHER ASSETS:	
Commodity derivative contracts	9,000
Deferred charges, net	2,800
Advances to operators and other assets	79,000
Total other assets	13,800
TOTAL ASSETS	\$ 133,000
LIABILITIES AND STOCKHOLDERS' EQUITY	
CURRENT LIABILITIES:	
Accounts payable	\$ 6,700
Revenue payable	6,700
Accrued interest	3,500

Accrued drilling and operating costs	6,3
Advances from non-operators	&n
Commodity derivative contracts	16
Commodity derivative premium payable	1,5
Asset retirement obligation	86
Other accrued liabilities	9,2
Total current liabilities	41
LONG-TERM LIABILITIES:	
Long-term debt	41
Commodity derivative contracts	61
Commodity derivative premium payable	4,0
Asset retirement obligation	5,8
Total long-term liabilities	42
Commitments and contingencies	
STOCKHOLDERS' EQUITY:	
Preferred stock, 40,000,000 shares authorized	
Series A Preferred stock, par value \$0.01 per share; 10,000,000 shares authorized; 4,045,000 shares issued and outstanding at June 30, 2015 and December 31, 2014, respectively, with liquidation preference of \$25.00 per share	41
Series B Preferred stock, par value \$0.01 per share; 10,000,000 shares authorized; 2,140,000 shares issued and outstanding at June 30, 2015 and December 31, 2014, respectively, with liquidation preference of \$25.00 per share	21
Common stock, par value \$0.001 per share; 275,000,000 shares authorized; 80,144,934 and 78,632,810 shares issued and outstanding at June 30, 2015 and December 31, 2014, respectively	78
Additional paid-in capital	56
Accumulated deficit	(3)
Total stockholders' equity	23
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$

GASTAR EXPLORATION INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Six Months Ended June 30,	
	2015	2014
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (loss) income	\$ (113,781)	\$ 7,238
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	30,551	22,662
Impairment of oil and natural gas properties	100,152	—
Stock-based compensation	2,773	2,532
Mark to market of commodity derivatives contracts:		
Total (gain) loss on commodity derivatives contracts	(8,433)	15,424
Cash settlements of matured commodity derivatives contracts, net	11,408	(6,061)
Cash premiums paid for commodity derivatives contracts	(45)	(155)
Amortization of deferred financing costs	1,736	1,491
Accretion of asset retirement obligation	256	247
Settlement of asset retirement obligation	(80)	(546)
Changes in operating assets and liabilities:		
Accounts receivable	15,887	(2,827)
Prepaid expenses	1,397	112
Accounts payable and accrued liabilities	(4,806)	9,649
Net cash provided by operating activities	37,015	49,766
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of oil and natural gas properties	(84,724)	(55,295)
Advances to operators	(1,225)	(20,657)
Acquisition of oil and natural gas properties - refund	—	4,209
Proceeds from sale of oil and natural gas properties	2,008	3,077
Deposit for sale of oil and natural gas properties	6,620	—
(Payments to) proceeds from non-operators	(1,820)	526
Purchase of furniture and equipment	(45)	(158)
Net cash used in investing activities	(79,186)	(68,298)
CASH FLOWS FROM FINANCING ACTIVITIES:		



Proceeds from revolving credit facility	55,000		35,000
Repayment of revolving credit facility	(5,000)		(15,000)
Proceeds from issuance of preferred stock, net of issuance costs	—		2,064
Dividends on preferred stock	(7,237)		(7,187)
Deferred financing charges	(797)		(319)
Tax withholding related to restricted stock and PBU vestings	(1,425)		(3,656)
Net cash provided by financing activities	40,541		10,902
NET DECREASE IN CASH AND CASH EQUIVALENTS	(1,630)		(7,630)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	11,008		32,393
CASH AND CASH EQUIVALENTS, END OF PERIOD	\$ 9,378		\$ 24,763

NON-GAAP FINANCIAL INFORMATION AND RECONCILIATION

We use both GAAP and certain non-GAAP financial measures to assess performance. Generally, a non-GAAP financial measure is a numerical measure of a company's performance, financial position or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. Our management believes that these non-GAAP measures provide useful supplemental information to investors in order that they may evaluate our financial performance using the same measures as management. These non-GAAP financial measures should not be considered as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP. In evaluating these measures, investors should consider that the methodology applied in calculating such measures may differ among companies and analysts. A reconciliation is provided below outlining the differences between these non-GAAP measures and their most directly comparable financial measure calculated in accordance with GAAP.

Reconciliation of Net (Loss) Income to Net Income (Loss) Excluding Special Items:

	For the
	2015
	(in thousands)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS AS REPORTED ⁽¹⁾	\$ (10,000)
SPECIAL ITEMS:	
Losses related to the change in mark to market value for outstanding commodity derivatives contracts	7,777
Impairment of natural gas and oil properties	100,100
Non-recurring general and administrative costs related to acquisition of assets	—
Non-recurring general and administrative costs related to Parent migration	—
Foreign transaction loss	—
ADJUSTED NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	\$ (10,000)
ADJUSTED NET (LOSS) INCOME PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:	
Basic	\$ (0.00)
Diluted	\$ (0.00)
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:	
Basic	77,610
Diluted	77,610

(1) The three and six months ended June 30, 2014 include the benefit of an \$8.6 million one-time adjustment related to an arbitration settlement.

Reconciliation of Cash Flows before Working Capital Changes

and as Adjusted for Special Items:

	For the Three Months Ended June 30,		For the S
	2015	2014	2015
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income ⁽¹⁾	\$ (114,395)	\$ 5,627	\$ (113,7
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	16,080	10,280	30,551
Impairment of oil and natural gas properties	100,152	—	100,152
Stock-based compensation	1,247	999	2,773
Mark to market of commodity derivatives contracts:			
Total loss (gain) on commodity derivatives contracts	1,790	8,910	(8,433)
Cash settlements of matured commodity derivatives contracts, net	6,131	(3,046)	11,408
Cash premiums paid for commodity derivatives contracts	(45)	(84)	(45)
Amortization of deferred financing costs	914	758	1,736
Accretion of asset retirement obligation	131	125	256
Settlement of asset retirement obligation	(80)	(289)	(80)
Cash flows from operations before working capital changes	11,925	23,280	24,537
Foreign transaction loss	—	4	—
Dividends on preferred stock	(3,619)	(3,611)	(7,237)
Non-recurring general and administrative costs related to acquisition of assets	—	—	—
Non-recurring general and administrative costs related to Parent migration	—	13	—
Adjusted cash flows from operations	\$ 8,306	\$ 19,686	\$ 17,300

(1) The three and six months ended June 30, 2014 include the benefit of an \$8.6 million one-time adjustment related to an arbitration settlement.

Reconciliation of Net (Loss) Income to Adjusted Earnings Before Interest, Income Taxes, Depreciation, Depletion and Amortization

	For the Three Months Ended	
	2015	2014
	(in thousands, except share)	
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS AS REPORTED ⁽¹⁾	\$ (118,014)	\$ 2,0
Interest expense	6,936	6,912
Depreciation, depletion and amortization	16,080	10,28
Impairment of oil and natural gas properties	100,152	&mda
EBITDA	5,154	19,20
Dividend expense	3,619	3,611
Accretion of asset retirement obligation	131	125
Losses related to the change in mark to market value for outstanding commodity derivatives contracts	7,777	5,418
Non-cash stock compensation expense	1,247	999
Foreign transaction loss	—	4
Investment income and other	(3)	(4)
Non-recurring general and administrative costs related to acquisition of assets	—	&mda
Non-recurring general and administrative costs related to Parent migration	—	13
Adjusted EBITDA	\$ 17,925	\$ 29,

(1) The three and six months ended June 30, 2014 include the benefit of an \$8.6 million one-time adjustment related to an arbitration settlement.

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