QEP RESOURCES REPORTS SECOND QUARTER 2016 FINANCIAL AND OPERATING RESULTS

- Delivered record net crude oil production of over 57,200 barrels per day
- Increased full-year crude oil and NGL production guidance
- Completed six gross-operated Spraberry Shale wells, with an average peak 24-hour IP of 1,465 Boed
- Continued strong performance from the Middle Bakken and the three evaluated benches of the Three Forks
- Entered into a purchase and sale agreement to acquire additional oil and gas properties in the core of the Permian Basin for approximately $600 million
- Maintained strong liquidity with over $1.0 billion in cash and cash equivalents at quarter-end, including approximately $413 million of net proceeds from an equity offering completed in June 2016

DENVER — July 27, 2016 — QEP Resources, Inc. (NYSE:QEP) (QEP or the Company) today reported second quarter 2016 financial and operating results. The Company reported a net loss of $197.0 million, or $0.90 per diluted share, for the second quarter 2016 compared with a net loss of $76.3 million, or $0.43 per diluted share, for the second quarter 2015. The net loss was primarily due to lower average realized prices for crude oil, natural gas liquids (NGL) and natural gas and lower natural gas volumes, partially offset by higher crude oil and NGL volumes and lower operating expenses.

Net loss includes non-cash gains and losses associated with the change in the fair value of derivative instruments, gains and losses from asset sales, asset impairments, and other non-cash and/or non-recurring items. Excluding these items, the Company's second quarter 2016 Adjusted Net Loss (a non-GAAP measure) was $50.2 million, or $0.23 per diluted share compared with Adjusted Net Income of $16.0 million, or $0.09 per diluted share, for the second quarter 2015.

Adjusted EBITDA (a non-GAAP measure) for the second quarter 2016 was $168.3 million compared with $279.4 million for the second quarter 2015, a 40% decrease, primarily due to lower average realized prices, partially offset by increased natural gas equivalent production and lower operating expenses. The definitions and reconciliations of Adjusted EBITDA and Adjusted Net Loss to net income (loss) are provided within the financial tables of this release.

"We continue to have great success with our Permian Basin horizontal drilling program targeting the Spraberry Shale," commented Chuck Stanley, Chairman, President and CEO of QEP. "The performance of the six new wells completed in the quarter, combined with continued strong production from earlier completions, resulted in record Permian production that averaged over 17,300 Boed during the quarter. These outstanding results are a direct reflection of our asset quality, superior execution, and enhanced completion design."

"In addition, our recently announced agreement to acquire additional properties in the Permian will add significant drilling inventory in the core of the northern Midland Basin. We expect to add two horizontal rigs on the acquired acreage by year-end 2016 with three horizontal rigs operating on the new acreage by year-end 2017. Our expanded footprint in this world-class crude oil basin, combined with our existing crude oil assets, will allow us to leverage our technical knowledge and operational synergies to efficiently drive crude oil production and reserve growth in 2017 and beyond."

"In the Williston Basin, strong performance from our infill and deeper bench test wells continues to exceed our expectations. Although we completed only one well in South Antelope in the quarter, we delivered record equivalent production driven by strong well performance from the 17 South Antelope wells completed in the first quarter of the year."

"As we enter the second half of the year, we remain focused on creating shareholder value by continuing to achieve operational and capital efficiencies across our asset portfolio. Despite an almost 50% year-over-year reduction in capital expenditures, we expect to maintain a relatively flat production profile in 2016," concluded Stanley.

Slides for the second quarter 2016 with maps and other supporting materials referred to in this release are posted on the Company's website at www.qepres.com.

QEP Financial Results Summary

- Natural gas equivalent production was 83.3 Bcfe for the second quarter 2016 compared with 80.9 Bcfe for the second quarter 2015, an increase of 3%. This increase was primarily due to increased production in the Permian, Williston and Uinta basins, partially offset by decreased production in Pinedale and Haynesville/Cotton Valley.
- Crude oil and NGL production increased 7% and 27%, respectively, while natural gas production decreased 4% in the second quarter 2016 compared with the second quarter 2015. Second quarter 2016 crude oil production was positively impacted by improved well results in the Permian and Williston basins. NGL production was higher, primarily in the Williston Basin, due to a third-party midstream provider's decision to continue to operate in ethane recovery and in the Permian Basin due to an overall increase in production.
- Field-level revenues decreased 20% in the second quarter 2016 compared with the second quarter 2015, due to lower crude oil, NGL and natural gas prices. Crude oil and NGL production accounted for 74% of field-level revenues in the second quarter 2016.
- Capital investment, excluding acquisitions, (on an accrual basis) for the second quarter 2016 was $85.7 million, down $71.3 million from the first quarter 2016. For the first six months of 2016, QEP's capital investment, excluding acquisitions, (on an accrual basis) was $242.7 million, down $257.2 million from the first six months of 2015.
- During the quarter, the Company invested $8.8 million to acquire various oil and gas properties in the Permian Basin, primarily purchasing undeveloped leaseholds.
- Cash and cash equivalents were $1,038.3 million at the end of the second quarter 2016, and the Company had no borrowings under its unsecured revolving credit facility.
- General and administrative expense for the second quarter 2016 was $43.7 million, a decrease of 15% compared with the second quarter 2015, driven primarily by a decrease in labor, benefits and other employee expenses and an $11.2 million non-cash pension curtailment loss related to changes in the Company's pension plan recognized in the second quarter 2015. In April 2016, QEP restructured and streamlined its organizational structure in response to the lower commodity price environment. This restructuring resulted in a 6% decrease in the Company's workforce and $1.8 million of one-time termination benefits in the second quarter 2016.

2016 Permian Acquisition Update

On June 21, 2016, the Company announced it had entered into a Purchase and Sale Agreement ("PSA") with certain individuals and entities ("Initial Sellers") to acquire approximately 9,400 net acres in the Permian Basin in Martin County, Texas for total consideration of approximately $600 million, subject to customary purchase price adjustments ("2016 Permian Acquisition"). The acreage is located 10 miles east of existing QEP operations in the core of the northern Midland Basin where QEP has identified potential for over 430 horizontal drilling locations in four target reservoirs. The PSA required the Initial Sellers to obtain executed joinders representing an aggregate allocated value of at least 90% of the total consideration of approximately $600 million, or QEP could terminate the PSA at its sole option. To date, joinders have been delivered representing $595 million (over 99% of the aggregate allocated value). The transaction is expected to be funded with proceeds from the June 2016 equity offering and cash on hand. QEP continues to conduct due diligence, and barring unexpected findings the parties expect the transaction to close on or before September 30, 2016. (See Slides 6-9)

In response to the current commodity price environment, QEP has reduced its full-year capital budget for drilling and completions by approximately 50% compared with 2015. Due to efficiency gains, strong well performance and ongoing cost reduction initiatives, the Company anticipates approximately flat year-over-year total production in 2016.

The guidance below assumes the following updates:

- Two additional rigs in the Permian Basin in the fourth quarter 2016 associated with the 2016 Permian Acquisition
- No production or operating expenses associated with 2016 Permian Acquisition

	2016 Previous Forecast	2016 Current Forecast
Oil production (MMbbl)	19.0 - 20.5	19.5 - 20.5
NGL production (MMbbl)	4 - 5	4.75 - 5.25
Natural gas production (Bcf)	165 - 175	165 - 175
Total natural gas equivalent production (Bcfe)	303 - 328	311 - 330
Lease operating and transportation expense (per Mcfe)	\$1.60 - \$1.70	\$1.60 - \$1.70
Depletion, depreciation and amortization (per Mcfe)	\$2.70 - \$3.00	\$2.55 - \$2.80
Production and property taxes (% of field-level revenue)	8.5%	8.5%
(in millions)		
General and administrative expense[(1)]	\$150 - \$160	\$165 - \$175
Capital investment (excluding acquisitions)	\$450 - \$500	\$500 - \$550

(1) Forecasted general and administrative expense includes approximately $40.0 million of non-cash expenses primarily related to share-based compensation and approximately $10.0 million of restructuring and legal expenses QEP does not expect to incur in the second half of 2016.

Operations Summary

The table below presents a summary of QEP-operated and non-operated well completions for the three and six months ended June 30, 2016:

	Operated Completions				Non-operated Completions			
	Three Months Ended June 30, 2016		Six Months Ended June 30, 2016		Three Months Ended June 30, 2016		Six Months Ended June 30, 2016	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale	4	3.4	4	3.4	—	—	—	—
Williston Basin	1	1.0	18	17.8	4	0.0	7	0.0
Uinta Basin	—	—	8	8.0	—	—	2	0.0
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	—	—	4	0.7	9	1.8
Permian Basin	6	6.0	13	12.7	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—

Permian Basin

Permian Basin net production averaged over 17.3 Mboed (83% liquids) during the second quarter 2016, a 4% increase compared with the first quarter 2016 and a 53% increase over the second quarter 2015. QEP completed and turned to sales six gross-operated horizontal wells during the second quarter 2016 (average working interest 100%) with an average peak 24-hour IP of 1,465 Boed from an average lateral length of 7,280 feet. All six wells were completed in the Spraberry Shale.

The six operated wells completed in the first quarter 2016 continued to deliver excellent results, averaging over 83 Mboe per well in the first 90 days of production (96 Mboe for the four Spraberry Shale wells and 57 Mboe for the two Middle Spraberry wells).

At the end of the second quarter 2016, the Company had two gross-operated horizontal wells waiting on completion (average working interest 100%) and one gross-operated horizontal well drilling (average working interest 100%), all in the Spraberry Shale.

Current average gross QEP-operated drilled and completed authorization for expenditure (AFE) well costs are $5.0 million for Spraberry wells, with costs associated with facilities and artificial lift adding approximately $0.7 million per well. At the end of the second quarter, the Company had one operated rig in the Permian Basin drilling horizontal wells.

Slides 11-14 depict QEP's acreage and activity in the Permian Basin.

Williston Basin

Williston Basin net production averaged approximately 57.9 Mboed (87% liquids) during the second quarter 2016, an 8% increase compared with the first quarter 2016 and a 10% increase over the second quarter 2015. The Company completed and turned to sales one gross-operated, high-density infill pilot well, in the Middle Bakken, during the second quarter 2016 (working interest 100%) in South Antelope.

The original 10 high-density infill pilot wells completed in 2015 continue to deliver strong results. The first pad of five horizontal wells, completed in the second quarter 2015, has averaged over 298 Mboe per well in the first 360 days of production, while the second pad of five wells, completed in the third quarter 2015, has averaged over 216 Mboe in the first 180 days of production.

The Company continues to test the second and third benches of the Three Forks Formation with 12 second bench horizontal wells and one third bench well currently producing. Wells in both horizons continue to outperform expectations and validate additional inventory on our Williston Basin acreage. The second bench well with the longest time on production has produced 339 Mboe in its first 360 days of production. The third bench well has produced 243 Mboe in its first 180 days of production. At the end of the second quarter 2016, there were five wells in the second bench of the Three Forks and four wells in the third bench of the Three Forks waiting on completion. One additional second bench well was actively drilling at the end of quarter. (See Slide 21)

During the second quarter 2016, the Company modified its completion design to "plug-and-perf" from sliding sleeve. The change was primarily driven by cost reductions that now make "plug-and-perf" completions, which provide incremental production at a slightly higher cost, more economic than sliding sleeve completions.

At the end of the second quarter 2016, QEP had 28 gross operated horizontal wells waiting on completion in the Williston Basin (average working interest 88%), comprised of 25 at South Antelope and three at Ft. Berthold. Of those 28 wells, 22 were sliding sleeve and six were "plug-and-perf" designs. In addition, the Company had interest in 25 gross non-operated horizontal wells waiting on completion (average working interest 6%) at the end of the quarter.

An ongoing commercial dispute with the entity that purchases, gathers and processes natural gas produced from oil wells on the Company's South Antelope acreage negatively impacted completion activities and production volumes during the quarter. Due to this dispute, the pace at which the Company is able to complete additional drilled and uncompleted wells during the third quarter 2016 at South Antelope may be impacted. Unless the parties resolve the dispute amicably, the matter will be decided in binding arbitration, which will likely conclude in the fourth quarter 2016.

Current average gross QEP-operated drilled and completed AFE well costs, assuming the new "plug-and-perf" completion design, are $5.5 million at South Antelope and $6.0 million at Ft. Berthold, with costs associated with facilities and artificial lift adding approximately $0.8 million per well at South Antelope and $1.1 million per well at Ft. Berthold. At the end of the second quarter 2016, the Company had one operated rig working in the Williston Basin on its South Antelope acreage.

Slides 15-20 depict QEP's acreage and activity in the Williston Basin.

Pinedale

Pinedale net production averaged 251 MMcfed (13% liquids), during the second quarter 2016, a 9% decrease compared with the first quarter 2016 and an 8% decrease over the second quarter 2015. There were four operated wells completed and turned to sales during the second quarter 2016 (average working interest 85%).

At the end of the second quarter, the Company had 32 gross-operated Pinedale wells waiting on completion (average working interest 53%) and eight wells being drilled (average working interest 49%).

Current average gross QEP-operated drilled and completed AFE well costs are $2.7 million in Pinedale, with costs associated with facilities and plunger lift adding approximately $0.2 million per well. At the end of the second quarter, the Company had one operated rig running in Pinedale.

Slides 21-22 depict QEP's acreage and activity in Pinedale.

Uinta Basin

Uinta Basin net production averaged 87 MMcfed (19% liquids) during the second quarter 2016, of which 56 MMcfed (8% liquids) was from the Lower Mesaverde play. This represents a 9% increase compared with the first quarter 2016 and a 9% increase over the second quarter 2015.

Current average gross QEP-operated drilled and completed directional vertical AFE well costs are $2.1 million in the Uinta Basin, with costs associated with facilities and artificial lift adding approximately $0.3 million per well.

At the end of the second quarter, the Company had no rigs operating in the Uinta Basin.

Slides 23-24 depict QEP's acreage and activity in the Lower Mesaverde play in the Uinta Basin.

Second Quarter 2016 Results Conference Call

QEP's management will discuss second quarter 2016 results in a conference call on Thursday, July 28, 2016, beginning at 9:00 a.m. EDT. The conference call can be accessed at www.qepres.com. You may also participate in the conference call by dialing (877) 869-3847 in the U.S. or Canada and (201) 689-8261 for international calls. A replay of the teleconference will be available on the website immediately after the call through August 28, 2016, or by dialing (877) 660-6853 in the U.S. or Canada and (201) 612-7415 for international calls, and then entering the conference ID # 13640602. In addition, QEP's slides for the second quarter 2016, with updated maps showing QEP's leasehold and current activity for key operating areas discussed in this release, can be found on the Company's website.

About QEP Resources, Inc.

QEP Resources, Inc. (NYSE:QEP) is an independent natural gas and crude oil exploration and production company focused in two regions of the United States: the Northern Region (primarily in Wyoming, North Dakota and Utah) and the Southern Region (primarily Texas and Louisiana). For more information, visit QEP's' website at: www.qepres.com.

Forward-Looking Statements

This release includes forward-looking statements within the meaning of Section 27(a) of the Securities Act of 1933, as amended, and Section 21(e) of the Securities Exchange Act of 1934, as amended. Forward-looking statements can be identified by words such as "anticipates," "believes," "forecasts," "plans," "estimates," "expects," "should," "will" or other similar expressions. Such statements are based on management's current expectations, estimates and projections, which are subject to a wide range of uncertainties and business risks. These forward-looking statements include, but are not limited to, statements regarding: our 2016 capital investment budget; the number and location of drilling rigs; anticipated production levels; the quality of our E&P asset portfolio; our focus on capital discipline; expected gross completed well costs and additional costs for facilities and artificial lift; forecasted production amounts, lease operating and transportation expense, depletion, depreciation and amortization expense, general and administrative expense, and production and property taxes, and related assumptions for such guidance; plans regarding ethane recovery; the amount of employee termination expense and the timing of the recognition of such expense; our extensive inventory of drilling locations; additional drilling inventory from the 2016 Permian Acquisition; driving production and reserve growth in 2017 and beyond; leveraging knowledge and operational synergies; the funding and closing date of the 2016 Permian Acquisition; and the use and importance of non-GAAP financial measures. Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: changes in natural gas, NGL and oil prices; liquidity constraints, including those resulting from the cost or unavailability of financing due to debt and equity capital and credit market conditions, changes in our credit rating, our compliance with loan covenants, the increasing credit pressure on our industry or demands for cash collateral by counterparties to derivative and other contracts; global geopolitical and macroeconomic factors; the activities of the Organization of Petroleum Exporting Countries (OPEC), including the ability of members of OPEC to agree to and maintain oil price and production controls and the ability of Iran to market its oil following the lifting of trade sanctions; the impact of Brexit; general economic conditions, including interest rates; changes in local, regional, national and global demand for natural gas, oil and NGL; changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, greenhouse gas or other emissions, natural resources, and fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures; impact of U.S. dollar exchange rates on oil, NGL and natural gas prices; elimination of federal income tax deductions for oil and gas exploration and development; drilling results; shortages of oilfield equipment, services and personnel; the availability of storage and refining capacity; operating risks such as unexpected drilling conditions; transportation constraints; weather conditions; changes in maintenance, service and construction costs; permitting delays; outcome of contingencies such as legal proceedings; inadequate supplies of water and/or lack of water disposal sources; and the other risks discussed in the Company's periodic filings with the Securities and Exchange Commission, including the Risk Factors section of the Company's Annual Report on Form 10-K for the year ended December 31, 2015 and Quarterly Report on Form 10-Q for the quarter ended June 30, 2016. QEP Resources undertakes no obligation to publicly correct or update the forward-looking statements in this news release, in other documents, or on the website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

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QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
REVENUES	(in millions, except per share amounts)			
Gas sales	**$ 79.2**	$ 111.9	**$ 164.3**	$ 233.9
Oil sales	**207.7**	250.4	**351.5**	429.2
NGL sales	**22.8**	26.1	**36.4**	45.2
Other revenue (loss)	**(0.5)**	5.2	**1.8**	9.6
Purchased gas and oil sales	**24.5**	181.0	**41.0**	324.8
Total Revenues	**333.7**	574.6	**595.0**	1,042.7
OPERATING EXPENSES				
Purchased gas and oil expense	**26.8**	183.2	**43.7**	329.1
Lease operating expense	**52.6**	57.1	**112.6**	118.9
Gas, oil and NGL transportation and other handling costs	**69.5**	73.0	**143.1**	138.1
Gathering and other expense	**1.6**	1.4	**2.9**	3.1
General and administrative	**43.7**	51.3	**92.4**	98.7
Production and property taxes	**20.7**	32.7	**38.5**	60.5
Depreciation, depletion and amortization	**209.7**	215.8	**449.7**	411.2
Exploration expenses	**0.4**	0.8	**0.7**	1.9
Impairment	**0.8**	0.5	**1,183.2**	20.5
Total Operating Expenses	**425.8**	615.8	**2,066.8**	1,182.0
Net gain (loss) from asset sales	**(0.8)**	24.5	**(0.3)**	(6.0)
OPERATING INCOME (LOSS)	**(92.9)**	(16.7)	**(1,472.1)**	(145.3)
Realized and unrealized gains (losses) on derivative contracts	**(180.5)**	(66.0)	**(129.6)**	14.9
Interest and other income (expense)	**(0.3)**	3.8	**2.0**	1.2
Interest expense	**(36.6)**	(36.2)	**(73.3)**	(73.0)
INCOME (LOSS) BEFORE INCOME TAXES	**(310.3)**	(115.1)	**(1,673.0)**	(202.2)
Income tax (provision) benefit	**113.3**	38.8	**612.2**	70.3
NET INCOME (LOSS)	**$ (197.0)**	$ (76.3)	**$ (1,060.8)**	$ (131.9)
Earnings (loss) per common share				
Basic	**$ (0.90)**	$ (0.43)	**$ (5.21)**	$ (0.75)
Diluted	**$ (0.90)**	$ (0.43)	**$ (5.21)**	$ (0.75)
Weighted-average common shares outstanding				
Used in basic calculation	**217.7**	176.7	**203.7**	176.4
Used in diluted calculation	**217.7**	176.7	**203.7**	176.4
Dividends per common share	**$ —**	$ 0.02	**$ —**	$ 0.04

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2016	December 31, 2015
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$ 1,038.3	$ 376.1
Accounts receivable, net	132.5	278.2
Income tax receivable	170.5	87.3
Fair value of derivative contracts	1.4	146.8
Gas, oil and NGL inventories, at lower of average cost or market	7.2	13.3
Prepaid expenses and other	21.4	30.1
Total Current Assets	1,371.3	931.8
Property, Plant and Equipment (successful efforts method for gas and oil properties)		
Proved properties	13,556.8	13,314.9
Unproved properties	670.2	691.0
Marketing and other	297.9	297.9
Materials and supplies	29.4	38.5
Total Property, Plant and Equipment	14,554.3	14,342.3
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	8,440.6	6,870.2
Marketing and other	95.1	87.5
Total Accumulated Depreciation, Depletion and Amortization	8,535.7	6,957.7
Net Property, Plant and Equipment	6,018.6	7,384.6
Fair value of derivative contracts	—	23.2
Other noncurrent assets	91.8	58.6
TOTAL ASSETS	$ 7,481.7	$ 8,398.2
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$ —	$ 29.8
Accounts payable and accrued expenses	213.8	351.7
Production and property taxes	39.7	46.1
Interest payable	37.9	36.4
Fair value of derivative contracts	46.6	0.8
Current portion of long-term debt	176.8	176.8
Total Current Liabilities	514.8	641.6
Long-term debt	2,017.8	2,014.7
Deferred income taxes	920.2	1,479.8
Asset retirement obligations	207.7	204.9
Fair value of derivative contracts	33.1	4.0
Other long-term liabilities	108.0	105.3
Commitments and contingencies		
EQUITY		
Common stock – par value $0.01 per share; 500.0 million shares authorized; 240.6 million and 177.3 million shares issued, respectively	2.4	1.8
Treasury stock – 1.0 million and 0.5 million shares, respectively	(20.6)	(14.6)
Additional paid-in capital	1,352.6	554.8
Retained earnings	2,357.5	3,418.3
Accumulated other comprehensive income	(11.8)	(12.4)
Total Common Shareholders' Equity	3,680.1	3,947.9
TOTAL LIABILITIES AND EQUITY	$ 7,481.7	$ 8,398.2

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	(in millions)	
OPERATING ACTIVITIES		
Net income (loss)	**$ (1,060.8)**	$ (131.9)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	**449.7**	411.2
Deferred income taxes	**(559.9)**	(29.4)
Impairment	**1,183.2**	20.5
Share-based compensation	**19.1**	15.6
Pension curtailment loss	**—**	11.2
Amortization of debt issuance costs and discounts	**3.2**	3.3
Net (gain) loss from asset sales	**0.3**	6.0
Unrealized (gains) losses on marketable securities	**(0.5)**	—
Unrealized (gains) losses on derivative contracts	**243.5**	181.8
Changes in operating assets and liabilities	**(58.2)**	(490.9)
Net Cash Provided by (Used in) Operating Activities	**219.6**	(2.6)
INVESTING ACTIVITIES		
Property acquisitions	**(23.6)**	—
Acquisition deposit held in escrow	**(30.0)**	—
Property, plant and equipment, including dry exploratory well expense	**(276.6)**	(651.3)
Proceeds from disposition of assets	**23.7**	(2.4)
Net Cash Provided by (Used in) Investing Activities	**(306.5)**	(653.7)
FINANCING ACTIVITIES		
Checks outstanding in excess of cash balances	**(29.8)**	(47.3)
Treasury stock repurchases	**(3.1)**	(1.9)
Other capital contributions	**0.2**	(0.1)
Dividends paid	**—**	(7.1)
Proceeds from issuance of common stock, net	**781.6**	—
Excess tax (provision) benefit on share-based compensation	**0.2**	(1.8)
Net Cash Provided by (Used in) Financing Activities	**749.1**	(58.2)
Change in cash and cash equivalents	**662.2**	(714.5)
Beginning cash and cash equivalents	**376.1**	1,160.1
Ending cash and cash equivalents	**$ 1,038.3**	$ 445.6

	Production by Region					
	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	**2016**	2015	Change
			(in Bcfe)			
Northern Region						
Pinedale	**22.8**	24.9	(8)%	**48.0**	46.7	3 %
Williston Basin	**31.6**	28.6	10 %	**61.0**	54.0	13 %
Uinta Basin	**7.9**	7.3	8 %	**15.2**	14.2	7 %
Other Northern	**2.1**	2.4	(13)%	**4.4**	5.1	(14)%
Total Northern Region	**64.4**	63.2	2 %	**128.6**	120.0	7 %
Southern Region						
Haynesville/Cotton Valley	**9.2**	10.4	(12)%	**18.3**	22.1	(17)%
Permian Basin	**9.5**	6.2	53 %	**18.6**	11.1	68 %
Other Southern	**0.2**	1.1	(82)%	**0.5**	2.9	(83)%
Total Southern Region	**18.9**	17.7	7 %	**37.4**	36.1	4 %
Total production	**83.3**	80.9	3 %	**166.0**	156.1	6 %

	Total Production					
	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	2016	2015	Change
Gas (Bcf)	**42.9**	44.5	(4)%	**86.3**	87.1	(1)%
Oil (Mbbl)	**5,209.5**	4,875.9	7 %	**10,385.9**	9,357.3	11 %
NGL (Mbbl)	**1,521.3**	1,198.0	27 %	**2,886.3**	2,145.4	35 %
Total production (Bcfe)	**83.3**	80.9	3 %	**166.0**	156.1	6 %
Average daily production (MMcfe)	**915.4**	889.0	3 %	**912.1**	862.4	6 %

	Prices					
	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	**2016**	2015	Change
Gas (per Mcf)						
Average field-level price	**$ 1.84**	$ 2.52		**$ 1.90**	$ 2.69	
Commodity derivative impact	**0.67**	0.63		**0.58**	0.53	
Net realized price	**$ 2.51**	$ 3.15	(20)%	**$ 2.48**	$ 3.22	(23)%
Oil (per bbl)						
Average field-level price	**$ 39.88**	$ 51.34		**$ 33.84**	$ 45.86	
Commodity derivative impact	**3.81**	13.24		**5.84**	15.88	
Net realized price	**$ 43.69**	$ 64.58	(32)%	**$ 39.68**	$ 61.74	(36)%
NGL (per bbl)						
Average field-level price	**$ 14.97**	$ 21.68		**$ 12.61**	$ 20.98	
Commodity derivative impact	**—**	—		**—**	—	
Net realized price	**$ 14.97**	$ 21.68	(31)%	**$ 12.61**	$ 20.98	(40)%
Average net equivalent price (per Mcfe)						
Average field-level price	**$ 3.72**	$ 4.80		**$ 3.33**	$ 4.54	
Commodity derivative impact	**0.59**	1.14		**0.67**	1.25	
Net realized price	**$ 4.31**	$ 5.94	(27)%	**$ 4.00**	$ 5.79	(31)%

	Operating Expenses					
	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Change	**2016**	2015	Change
			(per Mcfe)			
Lease operating expense	**$ 0.63**	$ 0.71	(11)%	**$ 0.68**	$ 0.76	(11)%
Gas, oil and NGL transport & other handling costs	**0.83**	0.90	(8)%	**0.86**	0.88	(2)%
Production and property taxes	**0.25**	0.40	(38)%	**0.23**	0.39	(41)%
Total production costs	**$ 1.71**	$ 2.01	(15)%	**$ 1.77**	$ 2.03	(13)%

QEP RESOURCES, INC.
NON-GAAP MEASURES
(Unaudited)

Adjusted EBITDA

This release contains references to the non-GAAP measure of Adjusted EBITDA. Management defines Adjusted EBITDA as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA) adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment, and certain other non-cash and/or non-recurring items. Management believes Adjusted EBITDA is an important measure of the Company's financial and operating performance that allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. The following tables reconcile net income to Adjusted EBITDA:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
	(in millions)			
Net income (loss)	**$ (197.0)**	$ (76.3)	**$ (1,060.8)**	$ (131.9)
Interest expense	**36.6**	36.2	**73.3**	73.0
Interest and other (income) expense	**0.3**	(3.8)	**(2.0)**	(1.2)
Income tax provision (benefit)	**(113.3)**	(38.8)	**(612.2)**	(70.3)
Depreciation, depletion and amortization	**209.7**	215.8	**449.7**	411.2
Unrealized (gains) losses on derivative contracts	**230.0**	158.3	**243.5**	181.8
Exploration expenses	**0.4**	0.8	**0.7**	1.9
Net (gain) loss from asset sales	**0.8**	(24.5)	**0.3**	6.0
Impairment	**0.8**	0.5	**1,183.2**	20.5
Other [(1)]	**—**	11.2	**7.7**	11.2
Adjusted EBITDA	**$ 168.3**	$ 279.4	**$ 283.4**	$ 502.2

(1) Adjusted for a non-cash pension curtailment loss that was incurred during the three and six months ended June 30, 2015, due to changes in the Company's pension plan and additional legal expenses incurred during the six months ended June 30, 2016. The Company believes that these costs do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the losses from the calculation of Adjusted EBITDA.

Adjusted Net Income (Loss)

This release also contains references to the non-GAAP measure of Adjusted Net Income (Loss). Management defines Adjusted Net Income (Loss) as earnings excluding gains and losses from asset sales, unrealized gains and losses on derivative contracts, asset impairments and certain other non-cash and/or non-recurring items. Management believes Adjusted Net Income (Loss) is useful to investors in assessing the Company's operational performance relative to other gas and oil producing companies.

The following table reconciles net loss to Adjusted Net Income (Loss):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
	(in millions, except earnings per share)			
Net income (loss)	**$ (197.0)**	$ (76.3)	**$ (1,060.8)**	$ (131.9)
Adjustments to net income (loss)				
Unrealized (gains) losses on derivative contracts	**230.0**	158.3	**243.5**	181.8
Income taxes on unrealized (gains) losses on derivative contracts	**(84.2)**	(57.9)	**(89.1)**	(66.5)
Net (gain) loss from asset sales	**0.8**	(24.5)	**0.3**	6.0
Income taxes on net (gain) loss from asset sales	**(0.3)**	9.0	**(0.1)**	(2.2)
Impairment	**0.8**	0.5	**1,183.2**	20.5
Income taxes on impairment	**(0.3)**	(0.2)	**(433.1)**	(7.5)
Other [1]	**—**	11.2	**7.7**	11.2
Income taxes on other	**—**	(4.1)	**(2.8)**	(4.1)
Total after tax adjustments to net income	**146.8**	92.3	**909.6**	139.2
Adjusted Net Income (Loss)	**$ (50.2)**	$ 16.0	**$ (151.2)**	$ 7.3
Earnings (Loss) per Common Share				
Diluted earnings per share	**$ (0.90)**	$ (0.43)	**$ (5.21)**	$ (0.75)
Diluted after-tax adjustments to net income (loss) per share	**0.67**	0.52	**4.47**	0.79
Diluted Adjusted Net Income per share	**$ (0.23)**	$ 0.09	**$ (0.74)**	$ 0.04
Weighted-average common shares outstanding				
Diluted	**217.7**	176.7	**203.7**	176.4

(1) Adjusted for a non-cash pension curtailment loss that was incurred during the three and six months ended June 30, 2015, due to changes in the Company's pension plan and additional legal expenses incurred during the six months ended June 30, 2016. The Company believes that these costs do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the losses from the calculation of Adjusted Net Income (Loss).

The following tables present open 2016 derivative positions as of July 22, 2016:

Production Commodity Derivative Swap Positions

Year	Index	Total Volumes	Average Swap Price per Unit
		(in millions)	
Gas sales		(MMBtu)	($/MMBtu)
2016	NYMEX HH	24.5	$ 2.78
2016	IFNPCR	30.6	$ 2.53
2017	NYMEX HH	76.7	$ 2.77
2017	IFNPCR	32.9	$ 2.51
2018	NYMEX HH	11.0	$ 2.87
Oil Sales		(bbls)	($/bbl)
2016	NYMEX WTI	6.1	$ 51.24
2017	NYMEX WTI	9.9	$ 50.74
2018	NYMEX WTI	1.8	$ 53.41

Production Gas Collars

Year	Index	Total Volume	Average Price Floor	Average Price Ceiling
		(in millions)		
		(MMBtu)	($/MMBtu)	($/MMBtu)
2016	NYMEX HH	3.1	$ 2.75	$ 3.89
2017	NYMEX HH	11.0	$ 2.50	$ 3.50

Production Gas Basis Swaps

Year	Index Less Differential	Index	Total Volumes	Weighted-Average Differential
			(in millions)	
			(MMBtu)	($/MMBtu)
2016	NYMEX HH	IFNPCR	15.3	$ (0.16)
2017	NYMEX HH	IFNPCR	51.1	$ (0.18)
2018	NYMEX HH	IFNPCR	7.3	$ (0.16)

Storage Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swap Price per MMBtu
			(in millions)	
Gas sales			(MMBtu)	($/MMBtu)
2016	SWAP	IFNPCR	2.4	$ 2.59
2017	SWAP	IFNPCR	2.8	$ 2.80
Gas purchases				
2016	SWAP	IFNPCR	2.4	$ 2.46