UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 001-36120

ANTERO RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**80-0162034** (IRS Employer Identification No.)
1615 Wynkoop Street **Denver, Colorado** (Address of principal executive offices)	**80202** (Zip Code)

(303) 357-7310
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) ☐ Yes ☒ No

The registrant had 277,029,931 shares of common stock outstanding as of July 24, 2015.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading “Item 1A. Risk Factors” in this Quarterly Report on Form 10-Q. These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity, and capital required for our development program;
- natural gas, natural gas liquids (“NGLs”), and oil prices;
- timing and amount of future production of natural gas, NGLs, and oil;
- hedging strategy and results;
- ability to utilize or monetize our firm transportation commitments;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs, and oil;
- leasehold or business acquisitions;
- costs of developing our properties;
- operations of Antero Midstream Partners LP;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations, and intentions.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering, processing, transportation, and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price volatility and continued low commodity prices, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, marketing and transportation risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs, and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2014 (our "2014 Form 10-K") on file with the Securities and Exchange Commission (the "SEC") and in "Item 1A. Risk Factors" of this Quarterly Report on Form 10-Q.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs, and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities, or changes in commodity prices, may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs, and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Quarterly Report on Form 10-Q.

PART I—FINANCIAL INFORMATION

ANTERO RESOURCES CORPORATION

Condensed Consolidated Balance Sheets
December 31, 2014 and June 30, 2015
(Unaudited)
(In thousands, except share amounts)

	2014	2015
Assets		
Current assets:		
Cash and cash equivalents	$ 245,979	143,286
Accounts receivable, net of allowance for doubtful accounts of $1,251 in 2014 and 2015	116,203	79,190
Accrued revenue	191,558	125,467
Derivative instruments	692,554	664,417
Other current assets	5,866	4,819
Total current assets	1,252,160	1,017,179
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	2,060,936	2,080,491
Proved properties	6,515,221	7,462,080
Fresh water distribution systems	421,012	441,692
Gathering systems and facilities	1,197,239	1,341,661
Other property and equipment	37,687	42,842
	10,232,095	11,368,766
Less accumulated depletion, depreciation, and amortization	(879,643)	(1,238,989)
Property and equipment, net	9,352,452	10,129,777
Derivative instruments	899,997	1,305,392
Other assets	68,886	80,133
Total assets	$ 11,573,495	12,532,481
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 531,564	326,638
Accrued liabilities	168,614	183,319
Revenue distributions payable	182,352	190,881
Deferred income tax liability	260,373	251,097
Other current liabilities	12,202	14,248
Total current liabilities	1,155,105	966,183
Long-term liabilities:		
Long-term debt	4,362,550	4,500,038
Deferred income tax liability	534,423	706,948
Derivative instruments	—	651
Other liabilities	47,587	49,215
Total liabilities	6,099,665	6,223,035
Contingencies (note 8)		
Equity:		
Stockholders' equity:		
Preferred stock, $0.01 par value; authorized - 50,000,000 shares; none issued	—	—
Common stock, $0.01 par value; authorized - 1,000,000,000 shares; issued and outstanding 262,071,642 shares and 277,025,288 shares, respectively	2,621	2,770
Additional paid-in capital	3,513,725	4,099,718
Accumulated earnings	867,447	1,116,505
Total stockholders' equity	4,383,793	5,218,993
Noncontrolling interest in consolidated subsidiary	1,090,037	1,090,453
Total equity	5,473,830	6,309,446
Total liabilities and equity	$ 11,573,495	12,532,481

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)
Three Months Ended June 30, 2014 and 2015
(Unaudited)
(In thousands, except share and per share amounts)

	2014	2015
Revenue:		
Natural gas sales	$ 314,151	242,065
Natural gas liquids sales	79,768	59,525
Oil sales	35,633	23,032
Gathering, compression, and water distribution	3,565	4,490
Marketing	1,987	49,829
Commodity derivative fair value losses	(123,766)	(2,227)
Total revenue	311,338	376,714
Operating expenses:		
Lease operating	5,021	6,673
Gathering, compression, processing, and transportation	103,837	166,669
Production and ad valorem taxes	21,358	22,519
Marketing	13,946	79,053
Exploration	6,703	628
Impairment of unproved properties	1,956	26,339
Depletion, depreciation, and amortization	105,154	177,046
Accretion of asset retirement obligations	309	408
General and administrative (including equity-based compensation expense of $32,474 and $27,582 in 2014 and 2015, respectively)	58,357	59,191
Contract termination and rig stacking	—	1,937
Total operating expenses	316,641	540,463
Operating loss	(5,303)	(163,749)
Other expenses:		
Interest	(37,260)	(59,823)
Loss on early extinguishment of debt	(20,386)	—
Total other expenses	(57,646)	(59,823)
Loss from continuing operations before income taxes and discontinued operations	(62,949)	(223,572)
Provision for income tax benefit	18,454	84,089
Loss from continuing operations	(44,495)	(139,483)
Discontinued operations:		
Income from sale of discontinued operations, net of income tax expense of $1,354	2,210	—
Loss and comprehensive loss including noncontrolling interest	(42,285)	(139,483)
Net income and comprehensive income attributable to noncontrolling interest	—	5,890
Loss and comprehensive loss attributable to Antero Resources Corporation	$ (42,285)	$ (145,373)
Earnings (loss) per common share		
Continuing operations	$ (0.17)	$ (0.52)
Discontinued operations	0.01	—
Total	$ (0.16)	$ (0.52)
Earnings (loss) per common share—assuming dilution		
Continuing operations	$ (0.17)	$ (0.52)
Discontinued operations	0.01	—
Total	$ (0.16)	$ (0.52)
Weighted average number of shares outstanding:		
Basic	262,049,659	277,002,786
Diluted	262,049,659	277,002,786

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)
Six Months Ended June 30, 2014 and 2015
(Unaudited)
(In thousands, except share and per share amounts)

	2014	2015
Revenue:		
Natural gas sales	$ 626,487	557,007
Natural gas liquids sales	153,696	138,311
Oil sales	59,755	35,489
Gathering, compression, and water distribution	7,089	10,658
Marketing	5,213	107,609
Commodity derivative fair value gains (losses)	(372,695)	757,327
Total revenue	479,545	1,606,401
Operating expenses:		
Lease operating	9,890	14,775
Gathering, compression, processing, and transportation	187,347	330,331
Production and ad valorem taxes	42,397	46,737
Marketing	25,927	152,402
Exploration	13,700	1,999
Impairment of unproved properties	3,353	34,916
Depletion, depreciation, and amortization	196,360	359,346
Accretion of asset retirement obligations	611	808
General and administrative (including equity-based compensation expense of $61,611 and $55,365 in 2014 and 2015, respectively)	109,342	118,240
Contract termination and rig stacking	—	10,902
Total operating expenses	588,927	1,070,456
Operating income (loss)	(109,382)	535,945
Other expenses:		
Interest	(68,602)	(113,008)
Loss on early extinguishment of debt	(20,386)	—
Total other expenses	(88,988)	(113,008)
Income (loss) from continuing operations before income taxes and discontinued operations	(198,370)	422,937
Provision for income tax (expense) benefit	59,116	(163,249)
Income (loss) from continuing operations	(139,254)	259,688
Discontinued operations:		
Income from sale of discontinued operations, net of income tax expense of $1,354	2,210	—
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(137,044)	259,688
Net income and comprehensive income attributable to noncontrolling interest	—	10,630
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (137,044)	249,058
Earnings (loss) per common share:		
Continuing operations	$ (0.53)	0.92
Discontinued operations	0.01	—
Total	$ (0.52)	0.92
Earnings (loss) per common share—assuming dilution		
Continuing operations	$ (0.53)	0.92
Discontinued operations	0.01	—
Total	$ (0.52)	0.92
Weighted average number of shares outstanding:		
Basic	262,049,659	271,181,132
Diluted	262,049,659	271,192,089

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION
Condensed Consolidated Statements of Equity
Six Months Ended June 30, 2015
(Unaudited)
(In thousands, except share amounts)

	Common Stock	Additional paid-in capital	Accumulated earnings	Noncontrolling interest	Total equity
Balances, December 31, 2014	$ 2,621	3,513,725	867,447	1,090,037	5,473,830
Issuance of 14,700,000 shares of common stock in public offering, net of underwriter discounts and offering costs	147	537,546	—	—	537,693
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income tax withholdings	2	(4,515)	—	—	(4,513)
Equity-based compensation	—	52,962	—	2,403	55,365
Net income and comprehensive income	—	—	249,058	10,630	259,688
Distributions to non-controlling interests	—	—	—	(12,617)	(12,617)
Balances, June 30, 2015	$ 2,770	4,099,718	1,116,505	1,090,453	6,309,446

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION
Condensed Consolidated Statements of Cash Flows
Six Months Ended June 30, 2014 and 2015
(Unaudited)
(In thousands)

	2014	2015
Cash flows from operating activities:		
Net income (loss) including noncontrolling interest	$ (137,044)	259,688
Adjustment to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization, and accretion	196,971	360,154
Impairment of unproved properties	3,353	34,916
Derivative fair value (gains) losses	372,695	(757,327)
Gains (losses) on settled derivatives	(118)	380,720
Deferred income tax expense (benefit)	(59,116)	163,249
Equity-based compensation expense	61,611	55,365
Loss on early extinguishment of debt	20,386	—
Gain on sale of discontinued operations	(3,564)	—
Deferred income tax expense—discontinued operations	1,354	—
Other	969	3,999
Changes in current assets and liabilities:		
Accounts receivable	(15,922)	(2,987)
Accrued revenue	(42,728)	66,091
Other current assets	(942)	1,047
Accounts payable	3,477	4,579
Accrued liabilities	42,475	10,904
Revenue distributions payable	57,503	8,529
Other current liabilities	(3,331)	1,668
Net cash provided by operating activities	498,029	590,595
Cash flows used in investing activities:		
Additions to unproved properties	(239,152)	(131,683)
Drilling and completion costs	(1,103,017)	(1,009,421)
Additions to fresh water distribution systems	(99,927)	(34,076)
Additions to gathering systems and facilities	(261,667)	(200,045)
Additions to other property and equipment	(11,041)	(2,794)
Change in other assets	(39,067)	(759)
Proceeds from asset sales	—	40,000
Net cash used in investing activities	(1,753,871)	(1,338,778)
Cash flows from financing activities:		
Issuance of common stock	—	537,693
Issuance of senior notes	600,000	750,000
Repayment of senior notes	(260,000)	—
Borrowings (repayments) on bank credit facility, net	952,000	(612,000)
Make-whole premium on debt extinguished	(17,383)	—
Payments of deferred financing costs	(16,989)	(15,254)
Distributions to noncontrolling interest in consolidated subsidiary	—	(12,617)
Other	—	(2,332)
Net cash provided by financing activities	1,257,628	645,490
Net increase (decrease) in cash and cash equivalents	1,786	(102,693)
Cash and cash equivalents, beginning of period	17,487	245,979
Cash and cash equivalents, end of period	$ 19,273	143,286
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest	$ 60,031	103,133
Supplemental disclosure of noncash investing activities:		
Increase (decrease) in accounts payable and accrued liabilities for additions to property and equipment	$ 126,657	(210,217)

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

(1) Organization

(a) Business and Organization

Antero Resources Corporation (individually referred to as "Antero") and its consolidated subsidiaries (collectively referred to as the "Company") are engaged in the exploitation, development, and acquisition of natural gas, natural gas liquids ("NGLs"), and oil properties in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs, and oil from unconventional formations. The Company has fresh water distribution operations in the Appalachian Basin, as well as gathering and compression operations through its consolidated subsidiary, Antero Midstream Partners LP ("Antero Midstream"), a publicly-traded limited partnership. The Company's corporate headquarters are in Denver, Colorado.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

These condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC applicable to interim financial information and should be read in the context of the December 31, 2014 consolidated financial statements and notes thereto for a more complete understanding of the Company's operations, financial position, and accounting policies. The December 31, 2014 consolidated financial statements have been filed with the SEC in the Company's 2014 Form 10-K.

The accompanying unaudited condensed consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information, and, accordingly, do not include all of the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, the accompanying unaudited condensed consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of June 30, 2015, the results of its operations for the three and six months ended June 30, 2014 and 2015, and its cash flows for the six months ended June 30, 2014 and 2015. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is identical to its comprehensive income or loss. Operating results for the period ended June 30, 2015 are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received for natural gas, NGLs, and oil, natural production declines, the uncertainty of exploration and development drilling results, and other factors.

The Company's exploration and production activities are accounted for under the successful efforts method.

As of the date these financial statements were filed with the SEC, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified.

(b) Principles of Consolidation

The accompanying condensed consolidated financial statements include the accounts of Antero Resources Corporation, its wholly-owned subsidiaries, and any entities in which the Company owns a controlling interest. All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements. Noncontrolling interest in the Company's consolidated financial statements represents the interests in Antero Midstream which are owned by third-party individuals or entities. An affiliate of the Company owns the general partner interest in Antero Midstream, as well as all of the incentive distribution rights. Noncontrolling interest is included as a component of equity in the Company's consolidated balance sheets.

(c) Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities, and disclosure of contingent assets and liabilities, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results could differ from those estimates.

The Company's condensed consolidated financial statements are based on a number of significant estimates including estimates of natural gas, NGLs, and oil reserve quantities, which are the basis for the calculation of depletion and impairment of oil and gas properties. Reserve estimates by their nature are inherently imprecise. Other items in the Company's consolidated financial statements which involve the use of significant estimates include derivative assets and liabilities, accrued revenue, deferred income taxes, equity-based compensation, asset retirement obligations, depreciation, amortization, and commitments and contingencies.

(d) Risks and Uncertainties

Historically, the market for natural gas, NGLs, and oil has experienced significant price fluctuations. Price fluctuations can result from variations in weather, levels of production in the region, availability of transportation capacity to other regions of the country, and various other factors. Increases or decreases in the prices the Company receives for its production could have a significant impact on the Company's future results of operations and reserve quantities.

(e) Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

(f) Derivative Financial Instruments

In order to manage its exposure to natural gas, NGLs, and oil price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, basis swap agreements, collar agreements, and other similar agreements relating to the price risk associated with a portion of its production. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligations. The fair value of our commodity derivative contracts of approximately $2.0 billion at June 30, 2015 includes the following values by bank counterparty: Citigroup - $402 million; Barclays - $358 million; JP Morgan - $319 million; Morgan Stanley - $261 million; Wells Fargo - $231 million; BNP Paribas - $193 million; Scotiabank - $115 million; Toronto Dominion - $44 million; Fifth Third - $35 million; Canadian Imperial Bank of Commerce - $8 million; and Bank of Montreal - $3 million. The credit ratings of certain of these banks were downgraded in recent years because of the sovereign debt crisis in Europe. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position.

The Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives are classified as revenues on the Company's condensed consolidated statements of operations. The Company's derivatives have not been designated as hedges for accounting purposes.

(g) Income Taxes

The Company recognizes deferred tax assets and liabilities for temporary differences resulting from net operating loss carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in the tax laws or tax rates is recognized in income in the period such changes are enacted.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion, or all, of the deferred tax assets will not be realized.

Unrecognized tax benefits represent potential future tax obligations for uncertain tax positions taken on previously filed tax returns that may not ultimately be sustained. The Company recognizes interest expense related to unrecognized tax benefits in interest expense and fines and penalties for tax-related matters as income tax expense.

(h) Fair Value Measurements

Financial Accounting Standards Board ("FASB") Accounting Standards Codification Topic 820, *Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., those measured at fair value in a business combination, the initial recognition of asset retirement obligations, and impairments of proved oil and gas properties, and other long-lived assets). Fair value is the price that the Company estimates would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value hierarchy is used to prioritize inputs to valuation techniques used to estimate fair value. An asset or liability subject to the fair value requirements is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The highest priority (Level 1) is given to unadjusted, quoted market prices in active markets for identical assets or liabilities, and the lowest priority (Level 3) is given to unobservable inputs. Level 2 inputs are data, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. Instruments which are valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter commodity price swaps and basis swaps. Valuation models used to measure fair value of these instruments consider various Level 2 inputs including (i) quoted forward prices for commodities, (ii) time value, (iii) quoted forward interest rates, (iv) current market prices and contractual prices for the underlying instruments, (v) risk of nonperformance by the Company and the counterparty, and (vi) other relevant economic measures.

(i) Industry Segments and Geographic Information

Management has evaluated how the Company is organized and managed and has identified the following segments: (1) the exploration, development, and production of natural gas, NGLs, and oil; (2) gathering and compression; (3) fresh water distribution; and (4) marketing of excess firm transportation capacity.

All of the Company's assets are located in the United States and substantially all of its production revenues are attributable to customers located in the United States.

(j) Marketing Revenues and Expenses

In 2014, the Company commenced activities to purchase and sell third-party natural gas and NGLs and to market its excess firm transportation capacity in order to utilize this excess capacity. Marketing revenues include sales of purchased third-party gas and NGLs, as well as revenues from the release of firm transportation capacity to others. Marketing expenses include the cost of purchased third-party natural gas and NGLs. The Company classifies firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize the capacity (excess capacity) as marketing expenses since it is marketing this excess capacity to third parties. Firm transportation for which the Company has sufficient production capacity (even though it may not use the transportation capacity because of alternative delivery points with more favorable pricing) is considered unutilized capacity. The costs of unutilized capacity are charged to transportation expense.

(k) Earnings (loss) per common share

Earnings (loss) per common share for each period is computed by dividing net income (loss) from continuing operations attributable to Antero or income (loss) from discontinued operations, as applicable, by the basic weighted average number of shares outstanding during such period. Earnings (loss) per common share—assuming dilution for each period is computed giving consideration to the potential dilution from outstanding equity awards, calculated using the treasury stock method. During periods in which the Company incurs a net loss, diluted weighted average shares outstanding are equal to basic weighted average shares outstanding because the effect of all equity awards is antidilutive. The following is a reconciliation of the Company's basic weighted average shares outstanding to diluted weighted average shares outstanding during the periods presented:

	Three months ended June 30,		Six months ended June 30,	
	2014	2015	2014	2015
Basic weighted average number of shares outstanding	262,049,659	277,002,786	262,049,659	271,181,132
Add: Dilutive effect of non-vested restricted stock and restricted stock units	—	—	—	10,957
Add: Dilutive effect of outstanding stock options	—	—	—	—
Diluted weighted average number of shares outstanding	262,049,659	277,002,786	262,049,659	271,192,089
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings (loss) per common share(1):				
Non-vested restricted stock and restricted stock units	1,956,015	2,376,661	1,010,182	2,140,586
Outstanding stock options	70,339	643,697	70,339	363,913

(1) The potential dilutive effects of these awards were excluded from the computation of earnings (loss) per common share—assuming dilution because the inclusion of these awards would have been anti-dilutive.

(3) Long-Term Debt

Long-term debt was as follows at December 31, 2014 and June 30, 2015 (in thousands):

	2014	2015
Antero:		
Bank credit facility(a)	$ 1,730,000	1,118,000
6.00% senior notes due 2020(c)	525,000	525,000
5.375% senior notes due 2021(d)	1,000,000	1,000,000
5.125% senior notes due 2022(e)	1,100,000	1,100,000
5.625% senior notes due 2023(f)	—	750,000
Net unamortized premium	7,550	7,038
	$ 4,362,550	4,500,038
Antero Midstream:		
Bank credit facility(b)	$ —	$ —

(a) Senior Secured Revolving Credit Facility

Antero has a senior secured revolving bank credit facility (the "Credit Facility") with a consortium of bank lenders. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of Antero's proved properties and commodity hedge positions and are subject to regular semiannual redeterminations. At June 30, 2015, the borrowing base was $4.0 billion and lender commitments were $4.0 billion, including $200 million of commitments under the Water Facility described below. The next redetermination of the borrowing base is scheduled to occur in October 2015. The maturity date of the Credit Facility is May 5, 2019.

On November 10, 2014, Antero and Antero Water LLC ("Antero Water") entered into a water credit facility (the "Water Facility"), in order to provide for separate borrowings attributable to Antero's fresh water distribution business, which contains covenants that are substantially identical to those under the Credit Facility. Borrowings under the Water Facility reduce availability under the Credit Facility on a dollar-for-dollar basis. The Water Facility will mature at the earlier of the sale of Antero Water or its assets to Antero Midstream, or May 12, 2016.

The Credit Facility and the Water Facility are ratably secured by mortgages on substantially all of Antero's properties and guarantees from Antero's restricted subsidiaries, as applicable. The Credit Facility and the Water Facility contain certain covenants, including restrictions on indebtedness and dividends, and, in the case of the Credit Facility, requirements with respect to working capital and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate, determined by Antero's election at the time of borrowing. Antero was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2014 and June 30, 2015.

As of December 31, 2014, Antero had an outstanding balance under the Credit Facility and Water Facility of $1.73 billion, with a weighted average interest rate of 2.06%, and outstanding letters of credit of $387 million. As of June 30, 2015, Antero had a total outstanding balance under the Credit Facility and Water Facility of $1.12 billion, with a weighted average interest rate of 2.07%, and outstanding letters of credit of $475 million. Commitment fees on the unused portion of the Credit Facility and the Water Facility are due quarterly at rates ranging from 0.375% to 0.50% of the unused portion of the facilities based on utilization.

(b) Senior Secured Revolving Credit Facility – Antero Midstream

On November 10, 2014, Antero Midstream entered into a senior secured revolving bank credit facility (the "Midstream Facility") with a consortium of bank lenders. At June 30, 2015, the maximum amount of the facility was $1.0 billion. The maturity date of the Midstream Facility is November 10, 2019.

The Midstream Facility is ratably secured by mortgages on substantially all of the properties of Antero Midstream and guarantees from its restricted subsidiaries, as applicable. The Midstream Facility contains certain covenants, including restrictions on indebtedness and certain distributions to owners, and requirements with respect to leverage and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate, determined by election at the time of borrowing. Antero Midstream was in compliance with all of the financial covenants under the Midstream Facility as of December 31, 2014 and June 30, 2015.

As of December 31, 2014 and June 30, 2015, Antero Midstream did not have a balance outstanding under the Midstream Facility. Commitment fees on the unused portion of the Midstream Facility are due quarterly at rates ranging from 0.25% to 0.375% of the unused facility based on utilization.

(c) 6.00% Senior Notes Due 2020

On November 19, 2012, Antero issued $300 million of 6.00% senior notes due December 1, 2020 (the "2020 notes") at par. On February 4, 2013, Antero issued an additional $225 million of the 2020 notes at 103% of par. The 2020 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2020 notes rank *pari passu* to Antero's other outstanding senior notes. The 2020 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2020 notes is payable on June 1 and December 1 of each year. Antero may redeem all or part of the 2020 notes at any time on or after December 1, 2015 at redemption prices ranging from 104.50% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, Antero may redeem up to 35% of the aggregate principal amount of the 2020 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the 2020 notes, plus accrued interest. At any time prior to December 1, 2015, Antero may redeem the 2020 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2020 notes, plus a "make-whole" premium and accrued interest. If Antero undergoes a change of control, the holders of the 2020 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2020 notes, plus accrued interest.

(d) 5.375% Senior Notes Due 2021

On November 5, 2013, Antero issued $1 billion of 5.375% senior notes due November 21, 2021 (the "2021 notes") at par. The 2021 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2021 notes rank *pari passu* to Antero's other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. Antero may redeem all or part of the 2021 notes at any time on or after November 1, 2016 at redemption prices ranging from 104.031% on or after November 1, 2016 to 100.00% on or after November 1, 2019. In addition, on or before November 1, 2016, Antero may redeem up to 35% of the aggregate principal amount of the 2021 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375% of the principal amount of the 2021 notes, plus accrued interest. At any time prior to November 1, 2016, Antero may also redeem the 2021 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2021 notes plus a "make-whole" premium and accrued interest. If Antero undergoes a change of control, the holders of the 2021 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2021 notes, plus accrued interest.

(e) 5.125% Senior Notes Due 2022

On May 6, 2014, Antero issued $600 million of 5.125% senior notes due December 1, 2022 (the "2022 notes") at par. On September 18, 2014, Antero issued an additional $500 million of the 2022 notes at 100.5% of par. The 2022 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2022 notes rank *pari passu* to Antero's other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. Antero may redeem all or part of the 2022 notes at any time on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, Antero may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125% of the principal amount of the 2022 notes, plus accrued interest. At any time prior to June 1, 2017, Antero may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a "make-whole" premium and accrued interest. If Antero undergoes a change of control prior to December 1, 2015, it may redeem all, but not less than all, of the 2022 notes at a redemption price equal to 110% of the principal amount of the 2022 notes. If Antero undergoes a change of control, the holders of the 2022 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued interest.

(f) 5.625% Senior Notes Due 2023

On March 17, 2015, Antero issued $750 million of 5.625% senior notes due June 1, 2023 (the "2023 notes") at par. The 2023 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2023 notes rank *pari passu* to Antero's other outstanding senior notes. The 2023 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2023 notes is payable on June 1 and December 1 of each year. Antero may redeem all or part of the 2023 notes at any time on or after June 1, 2018 at redemption prices ranging from 104.219% on or after June 1, 2018 to 100.00% on or after June 1, 2021. In addition, on or before June 1, 2018, Antero may redeem up to 35% of the aggregate principal amount of the 2023 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.625% of the principal amount of the 2023 notes, plus accrued interest. At any time prior to June 1, 2018, Antero may also redeem the 2023 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2023 notes plus a "make-whole" premium and accrued interest. If Antero undergoes a change of control prior to June 1, 2016, it may redeem all, but not less than all, of the 2023 notes at a redemption price equal to 110% of the principal amount of the 2023 notes. If Antero undergoes a change of control, the holders of the 2023 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2023 notes, plus accrued interest.

(g) Treasury Management Facility

Antero has a stand-alone revolving note with a lender under the Credit Facility which provides for up to $25 million of cash management obligations in order to facilitate Antero's daily treasury management. Borrowings under the revolving note are secured by the collateral for the Credit Facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on May 1, 2016. At December 31, 2014 and June 30, 2015, there were no outstanding borrowings under this facility.

(4) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the six months ended June 30, 2015 (in thousands).

Asset retirement obligations at December 31, 2014	$ 16,614
Obligations incurred for wells drilled	1,846
Accretion expense	808
Asset retirement obligations at June 30, 2015	$ 19,268

Asset retirement obligations are included in other liabilities on the condensed consolidated balance sheets.

(5) Equity-Based Compensation

Antero is authorized to grant up to 16,906,500 shares of common stock to employees and directors of the Company under the Antero Resources Corporation Long-Term Incentive Plan (the "Plan"). The Plan allows equity-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent awards, and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of Antero's Board of Directors. A total of 13,420,672 shares were available for future grant under the Plan as of June 30, 2015.

In connection with the Antero Midstream IPO, Antero Midstream's general partner adopted the Antero Midstream Partners LP Long-Term Incentive Plan (the "Midstream Plan"), pursuant to which non-employee directors of Antero Midstream's general partner and certain officers, employees, and consultants of Antero Midstream's general partner and its affiliates (which include Antero) are eligible to receive awards representing ownership interests in Antero Midstream. An aggregate of 10,000,000 common units may be delivered pursuant to awards under the Midstream Plan, subject to customary adjustments. A total of 7,654,863 common units are available for future grant under the Midstream Plan as of June 30, 2015.

The Company's equity-based compensation expense was as follows for the three and six months ended June 30, 2014 and 2015 (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2014	2015	2014	2015
Profits interests awards	$24,079	12,363	52,768	27,081
Restricted stock awards	8,287	10,235	8,596	18,671
Stock options	108	642	247	771
Antero Midstream phantom and restricted unit awards	—	4,267	—	8,692
Common stock issued to directors in lieu of cash compensation	—	75	—	150
Total expense	$32,474	27,582	61,611	55,365

Profits Interests Awards

In connection with its formation in October 2009, Antero Resources LLC issued profits interests to Antero Resources Employee Holdings LLC ("Employee Holdings"), which is owned solely by certain of the Company's officers and employees. These profits interests provide for the participation in distributions upon liquidation events meeting certain requisite financial return thresholds. In turn, Employee Holdings issued membership interests to certain of the Company's officers and employees. The Employee Holdings interests in Antero Resources LLC were exchanged for similar interests in Antero Investment in connection with the Company's initial public offering on October 16, 2013.

The limited liability company agreement of Antero Investment provides a mechanism that demonstrates how the shares of the Company's common stock will be allocated among the members of Antero Investment, including Employee Holdings. As a result of the adoption of the Antero Investment Limited Liability Company Agreement, the satisfaction of all performance and service conditions relative to the profits interest awards held by Employee Holdings in Antero Investment became probable. Accordingly, the Company has recognized approximately $476 million of equity-based compensation expense for the vested profits interests through June 30, 2015 and will recognize approximately $10 million over the remaining service period. Because consideration for the profits interest awards is deemed given by Antero Investment, the charge to equity-based compensation expense is accounted for as a capital contribution by Antero Investment to the Company and credited to additional paid-in capital. All available profits interest awards were made prior to the date of the IPO, and no additional profits interest awards will be made.

Restricted Stock and Restricted Stock Unit Awards

Restricted stock and restricted stock unit awards vest subject to the satisfaction of service requirements. Expense related to each restricted stock and restricted stock unit award is recognized on a straight-line basis over the requisite service period of the entire award, less awards expected to be forfeited. The grant date fair values of these awards are determined based on the closing price of the Company's common stock on the date of the grant. A summary of restricted stock and restricted stock unit awards activity during the six months ended June 30, 2015 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2014	1,983,673	$ 64.71	$ 80,497
Granted	871,127	$ 40.95	
Vested	(354,758)	$ 64.60	
Forfeited	(10,465)	$ 39.98	
Total awarded and unvested—June 30, 2015	2,489,577	$ 56.54	$ 85,492

Intrinsic values are based on the closing price of the Company's stock on the referenced dates. Unamortized expense of $120.4 million at June 30, 2015 is expected to be recognized over a weighted average period of approximately 3.0 years.

Stock Options

Stock options granted under the Plan vest over periods from one to four years and have a maximum contractual life of 10 years. Expense related to stock options is recognized on a straight-line basis over the requisite service period of the entire award, less awards expected to be forfeited. Stock options are granted with an exercise price equal to or greater than the market price of the Company's common stock on the date of grant. A summary of stock option activity for the six months ended June 30, 2015 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2014	81,021	$ 53.92	8.92	$ —
Options granted	665,366	$ 50.00		
Options exercised	—	—		
Options cancelled	(3,833)	$ 50.00		
Options expired	—	—		
Outstanding at June 30, 2015	742,554	$ 50.43	9.64	$ —
Vested or expected to vest as of June 30, 2015	742,554	$ 50.43	9.64	$ —
Exercisable at June 30, 2015	25,339	$ 54.15	8.29	$ —

Intrinsic value is based on the exercise price of the options and the closing price of the Company's stock on the referenced dates.

A Black-Scholes option-pricing model is used to determine the grant-date fair value of the Company's stock options. Expected volatility was derived from the volatility of the historical stock prices of a peer group of similar publicly traded companies' stock prices. The risk-free interest rate was determined using the implied yield available for zero-coupon U.S. government issues with a remaining term approximating the expected life of the options. A dividend yield of zero was assumed.

The following table presents information regarding the weighted average fair value for options granted in 2014 and 2015 and the assumptions used to determine fair value.

	2014	2015
Dividend yield	— %	— %
Volatility	40 %	40 %
Risk-free interest rate	1.75 %	1.66 %
Expected life (years)	5.50	6.25
Weighted average fair value of options granted	$ 20.55	$ 14.74

As of June 30, 2015, there was $10.0 million of unrecognized equity-based compensation expense related to nonvested stock options. That expense is expected to be recognized over a weighted average period of approximately 3.7 years.

Antero Midstream Partners Phantom and Restricted Unit Awards

Restricted units and phantom units granted by Antero Midstream vest subject to the satisfaction of service requirements, upon the completion of which common units in Antero Midstream are delivered to the holder of the restricted units or phantom units. These restricted and phantom units are treated, for accounting purposes, as if Antero Midstream distributed the units to Antero. Antero recognizes compensation expense as the units are granted to employees, and a portion of the expense is allocated to Antero Midstream. Expense related to each restricted unit and phantom unit award is recognized on a straight-line basis over the requisite service period of the entire award, less awards expected to be forfeited. The grant date fair values of these awards are determined based on the closing price of Antero Midstream's common units on the date of grant. A summary of restricted unit and phantom unit awards activity during the six months ended June 30, 2015 is as follows:

	Number of units	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2014	2,381,440	$ 29.00	$ 65,490
Granted	12,057	$ 24.88	
Vested	—	$ —	
Forfeited	(48,360)	$ 29.00	
Total awarded and unvested—June 30, 2015	2,345,137	$ 28.98	$ 67,165

Intrinsic values are based on the closing price of Antero Midstream's common units on the referenced dates. Unamortized expense of $56.7 million at June 30, 2015 is expected to be recognized over a weighted average period of approximately 3.3 years.

(6) Financial Instruments

The carrying values of accounts receivable and accounts payable at December 31, 2014 and June 30, 2015 approximated market value because of their short-term nature. The carrying values of the amounts outstanding under the Credit Facility and Water Facility at December 31, 2014 and June 30, 2015 approximated fair value because the variable interest rates are reflective of current market conditions.

Based on Level 2 market data inputs, the fair value of the Company's senior notes was approximately $2.5 billion at December 31, 2014 and $3.3 billion at June 30, 2015.

See note 7 for information regarding the fair value of derivative financial instruments.

(7) Derivative Instruments

(a) Commodity Derivatives

The Company periodically enters into natural gas, NGLs, and oil derivative contracts with counterparties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas, NGLs, and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas, NGLs, and oil recognized upon the ultimate sale of the Company's production.

For the six months ended June 30, 2014 and 2015, the Company was party to various natural gas, NGLs, and oil fixed price swap contracts. When actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the excess to the counterparty. When actual commodity prices are below the contractually provided fixed price, the Company receives the difference from the counterparty. In addition, the Company has entered into basis swap contracts in order to hedge the difference between the New York Mercantile Exchange ("NYMEX") index price and a local index price. The Company's derivative swap contracts have not been designated as hedges for accounting purposes; therefore, all gains and losses are recognized in the Company's statements of operations.

As of June 30, 2015, the Company's fixed price natural gas, NGLs, and oil swap positions from July 1, 2015 through December 31, 2021 were as follows (abbreviations in the table refer to the index to which the swap position is tied, as follows: TCO=Columbia Gas Transmission; NYMEX=Henry Hub; CGTLA=Columbia Gas Louisiana Onshore; CCG=Chicago City Gate; NYMEX-WTI=West Texas Intermediate; Mont Belvieu-TET=Mont Belvieu Propane):

	Natural gas MMbtu/day	Oil Bbls/day	Propane Bbls/day	Weighted average index price
Three months ending September 30, 2015:				
TCO ($/MMBtu)	120,000	—	—	$ 4.93
Dominion South ($/MMBtu)	230,000	—	—	$ 5.48
NYMEX ($/MMBtu)	770,000	—	—	$ 3.79
CGTLA ($/MMBtu)	40,000	—	—	$ 3.93
NYMEX-WTI ($/Bbl)	—	3,000	—	$ 64.84
Mont Belvieu-TET ($/Gallon)	—	—	23,000	$ 0.62
Total	1,160,000	3,000	23,000	
Three months ending December 31, 2015:				
TCO ($/MMBtu)	120,000	—	—	$ 5.14
Dominion South ($/MMBtu)	230,000	—	—	$ 5.74
NYMEX ($/MMBtu)	770,000	—	—	$ 3.92
CGTLA ($/MMBtu)	40,000	—	—	$ 4.09
NYMEX-WTI ($/Bbl)	—	3,000	—	$ 65.67
Mont Belvieu-TET ($/Gallon)	—	—	23,000	$ 0.64
Total	1,160,000	3,000	23,000	
Year ending December 31, 2016:				
TCO ($/MMBtu)	60,000		—	$ 4.91
Dominion South ($/MMBtu)	272,500		—	$ 5.35
NYMEX ($/MMBtu)	960,000		—	$ 3.56
CGTLA ($/MMBtu)	170,000		—	$ 4.09
Mont Belvieu-TET ($/Gallon)	—		30,000	$ 0.59
Total	1,462,500		30,000	
Year ending December 31, 2017:				
NYMEX ($/MMBtu)	660,000		—	$ 3.81
CGTLA ($/MMBtu)	420,000		—	$ 4.27
CCG ($/MMBtu)	70,000		—	$ 4.57
Mont Belvieu-TET ($/Gallon)	—		2,000	$ 0.64
Total	1,150,000		2,000	
Year ending December 31, 2018:				
NYMEX ($/MMBtu)	1,402,500		—	$ 4.25
Mont Belvieu-TET ($/Gallon)	—		2,000	$ 0.65
Total	1,402,500		2,000	
Year ending December 31, 2019:				
NYMEX ($/MMBtu)	1,537,500			$ 4.05
Year ending December 31, 2020:				
NYMEX ($/MMBtu)	1,010,000			$ 3.82
Year ending December 31, 2021:				
NYMEX ($/MMBtu)	100,000			$ 3.74

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Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

As of June 30, 2015, the Company's natural gas basis swap positions which settle on the pricing index to basis differential of TCO to the NYMEX Henry Hub natural gas price, are as follows:

	Natural gas MMbtu/day	Hedged Differential
Year ending December 31, 2015:	390,000	$ (0.35)
Year ending December 31, 2016:	290,000	$ (0.42)
Year ending December 31, 2017:	125,000	$ (0.49)

As of June 30, 2015, the Company's natural gas basis swap positions which settle on the pricing index to basis differential of NYMEX Henry Hub to the TCO natural gas price, are as follows:

	Natural gas MMbtu/day	Hedged Differential
Year ending December 31, 2016:	105,000	$ 0.28
Year ending December 31, 2017:	125,000	$ 0.30

(b) Summary

The following is a summary of the fair values of the Company's derivative instruments and where such values are recorded in the consolidated balance sheets as of December 31, 2014 and June 30, 2015. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	December 31, 2014		June 30, 2015	
	Balance sheet location	Fair value	Balance sheet location	Fair value
		(In thousands)		(In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$ 692,554	Current assets	$ 664,417
Commodity contracts	Long-term assets	899,997	Long-term assets	1,305,392
Total asset derivatives		1,592,551		1,969,809
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	—	Current liabilities	—
Commodity contracts	Long-term liabilities	—	Long-term liabilities	651
Total liability derivatives		—		651
Net derivatives		$ 1,592,551		$ 1,969,158

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Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

The following table presents the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets as of the dates presented, all at fair value (in thousands):

	December 31, 2014			June 30, 2015		
	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets (liabilities) on balance sheet
Commodity derivative assets	$1,621,665	(29,114)	1,592,551	$2,020,250	(50,441)	1,969,809
Commodity derivative liabilities	$ —	—	—	$ (1,132)	481	(651)

The following is a summary of derivative fair value gains (losses) and where such values are recorded in the condensed consolidated statements of operations for three and six months ended June 30, 2014 and 2015 (in thousands):

	Statement of operations location	Three months ended June 30, 2014	Three months ended June 30, 2015	Six months ended June 30, 2014	Six months ended June 30, 2015
Commodity derivative fair value gains (losses)	Revenue	$(123,766)	(2,227)	(372,695)	757,327

The fair value of commodity derivative instruments was determined using Level 2 inputs.

(8) Contingencies

The Company is the subject of two nearly identical lawsuits brought by South Jersey Gas Company and South Jersey Resources Group, LLC (collectively "SJGC") filed on February 4, 2015 in the Superior Court of New Jersey. The lawsuits have since been consolidated into one case. SJGC are purchasers of some of the Company's natural gas production under contracts entered into in 2011. Deliveries under the contracts began in October 2011 and the delivery obligation continues through October 2019. SJGC allege that the index prices specified in the contracts, and the index prices at which SJGC paid for deliveries from 2011 through September 2014, are no longer appropriate under the contracts because a market disruption event (as defined by the contract) has occurred and, as a result, a new index price is to be determined by the parties. The lawsuit seeks a reformation of the contracts, compensatory and punitive damages to be determined at trial, and costs and expenses of the actions. Beginning in October 2014, SJGC began paying the Company under indexes unilaterally selected by SJGC and not specified in the contract. The Company contends that no market disruption event has occurred and that SJGC has breached the contracts by failing to pay the Company based on the express price terms of the contracts. The Company further contends that jurisdiction and venue are improper in New Jersey. On March 30, 2015, the Company filed suit against SJGC in United States District Court in Colorado seeking relief for breach of contract, damages in the amounts that SJGC has short paid and continues to short pay, as well as costs of the suit. Through June 30, 2015, the Company estimates that it is owed approximately $22.5 million more than SJGC has paid using the indexes unilaterally selected by them.

The Company is party to various other legal proceedings and claims in the ordinary course of its business. The Company believes that certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on the Company's consolidated financial position, results of operations, or liquidity.

(9) Contract Termination and Rig Stacking

During the three and six months ended June 30, 2015, the Company incurred $1.9 million and $10.9 million of costs, respectively, for the delay or cancelation of drilling contracts with third-party contractors.

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

(10) Segment Information

See note 2(i) for a description of the Company's determination of its reportable segments. Operating segments are evaluated based on their contribution to consolidated results, which is determined by the respective operating income of each segment. General and administrative expenses are allocated to the gathering and compression and fresh water distribution segments based on estimates of labor and overhead expenditures on those activities. General and administrative expenses related to the marketing segment are not allocated because they are immaterial. Other income, income taxes, and interest expense are primarily managed and evaluated on a consolidated basis. Intersegment sales are transacted at prices which approximate market. Accounting policies for each segment are the same as the Company's accounting policies described in note 2 to the condensed consolidated financial statements.

The operating results and assets of the Company's reportable segments were as follows for the three months ended June 30, 2014 and 2015 (in thousands):

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2014:						
Sales and revenues:						
Third-party	$ 305,786	2,017	1,548	1,987	—	311,338
Intersegment	—	14,906	38,970	—	(53,876)	—
Total	$ 305,786	16,923	40,518	1,987	(53,876)	311,338
Operating expenses:						
Lease operating	$ 5,021	—	10,156	—	(10,156)	5,021
Gathering, compression, processing, and transportation	116,547	2,196	—	—	(14,906)	103,837
Depletion, depreciation, and amortization	93,057	8,656	3,441	—	—	105,154
General and administrative expense	50,484	5,780	2,093	—	—	58,357
Other operating expenses	28,996	—	1,330	13,946	—	44,272
Total	294,105	16,632	17,020	13,946	(25,062)	316,641
Operating income (loss)	$ 11,681	291	23,498	(11,959)	(28,814)	(5,303)
Segment assets	$6,861,624	898,270	348,629	—	(63,315)	8,045,208
Capital expenditures for segment assets	$ 817,871	154,144	39,897	—	(28,814)	983,098

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2015:						
Sales and revenues:						
Third-party	$ 322,395	2,664	1,826	49,829	—	376,714
Intersegment	277	53,929	28,836	—	(83,042)	—
Total	$ 322,672	56,593	30,662	49,829	(83,042)	376,714
Operating expenses:						
Lease operating	$ 6,477	—	5,851	—	(5,655)	6,673
Gathering, compression, processing, and transportation	213,560	7,105	—	—	(53,996)	166,669
Depletion, depreciation, and amortization	155,586	15,298	6,162	—	—	177,046
General and administrative expense	47,242	9,917	2,242	—	(210)	59,191
Other operating expenses	46,866	4,187	778	79,053	—	130,884
Total	469,731	36,507	15,033	79,053	(59,861)	540,463
Operating income (loss)	$ (147,059)	20,086	15,629	(29,224)	(23,181)	(163,749)
Segment assets	$10,920,171	1,408,969	416,910	17,668	(231,237)	12,532,481
Capital expenditures for segment assets	$ 544,367	74,057	11,950	—	(23,181)	607,193

The operating results and assets of the Company's reportable segments were as follows for the six months ended June 30, 2014 and 2015 (in thousands):

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2014:						
Sales and revenues:						
Third-party	$ 467,243	2,947	4,142	5,213	—	479,545
Intersegment	—	25,749	61,135	—	(86,884)	—
Total	$ 467,243	28,696	65,277	5,213	(86,884)	479,545
Operating expenses:						
Lease operating	$ 9,890	—	14,430	—	(14,430)	9,890
Gathering, compression, processing, and transportation	209,959	3,137	—	—	(25,749)	187,347
Depletion, depreciation, and amortization	175,237	14,764	6,359	—	—	196,360
General and administrative expense	95,800	9,556	3,986	—	—	109,342
Other operating expenses	57,674	—	2,387	25,927	—	85,988
Total	548,560	27,457	27,162	25,927	(40,179)	588,927
Operating income (loss)	$ (81,317)	1,239	38,115	(20,714)	(46,705)	(109,382)
Segment assets	$6,861,624	898,270	348,629	—	(63,315)	8,045,208
Capital expenditures for segment assets	$1,399,915	261,667	99,927	—	(46,705)	1,714,804

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2015:						
Sales and revenues:						
Third-party	$ 1,488,134	4,965	5,693	107,609	—	1,606,401
Intersegment	627	103,871	59,399	—	(163,897)	—
Total	$ 1,488,761	108,836	65,092	107,609	(163,897)	1,606,401
Operating expenses:						
Lease operating	$ 14,260	—	12,603	—	(12,088)	14,775
Gathering, compression, processing, and transportation	419,239	15,093	—	—	(104,001)	330,331
Depletion, depreciation, and amortization	317,091	29,973	12,282	—	—	359,346
General and administrative expense	94,659	19,418	4,660	—	(497)	118,240
Other operating expenses	85,836	7,888	1,638	152,402	—	247,764
Total	931,085	72,372	31,183	152,402	(116,586)	1,070,456
Operating income (loss)	$ 557,676	36,464	33,909	(44,793)	(47,311)	535,945
Segment assets	$10,920,171	1,408,969	416,910	17,668	(231,237)	12,532,481
Capital expenditures for segment assets	$ 1,191,209	200,045	34,076	—	(47,311)	1,378,019

(11) Subsidiary Guarantors

Antero's wholly-owned subsidiaries each have fully and unconditionally guaranteed Antero's senior notes. Antero Midstream and its subsidiary have been designated unrestricted subsidiaries under the Credit Facility and the indentures governing Antero's senior notes, and do not guarantee any of Antero's obligations (see note 3). In the event a subsidiary guarantor is sold or disposed of (whether by merger, consolidation, the sale of a sufficient amount of its capital stock so that it no longer qualifies as a "Subsidiary" of the Company (as defined in the indentures governing the notes) or the sale of all or substantially all of its assets (other than by lease)) and whether or not the subsidiary guarantor is the surviving entity in such transaction to a person which is not Antero or a restricted subsidiary of Antero, such subsidiary guarantor will be released from its obligations under its subsidiary guarantee if the sale or other disposition does not violate the covenants set forth in the indentures governing the notes.

In addition, a subsidiary guarantor will be released from its obligations under the indentures and its guarantee, upon the release or discharge of the guarantee of other Indebtedness (as defined in the indentures governing the notes) that resulted in the creation of such guarantee, except a release or discharge by or as a result of payment under such guarantee; if Antero designates such subsidiary as an unrestricted subsidiary and such designation complies with the other applicable provisions of the indentures governing the notes or in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the notes.

The following Condensed Consolidating Balance Sheets at December 31, 2014 and June 30, 2015, and the related statements of operations and comprehensive income (loss) and statements of cash flows for the three and six months ended June 30, 2015 present financial information for Antero on a stand-alone basis (carrying its investment in wholly-owned subsidiaries using the equity method), financial information for the subsidiary guarantors, financial information for the non-guarantor subsidiaries, and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. Antero's wholly-owned subsidiaries during the three and six months ended June 30, 2014 had no revenues, expenses, or cash flows. Antero's wholly-owned subsidiaries are not restricted from making distributions to the Parent.

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

Condensed Consolidating Balance Sheets
December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 15,787	—	230,192	—	245,979
Accounts receivable, net	116,203	—	—	—	116,203
Intercompany receivables	1,380	—	17,646	(19,026)	—
Accrued revenue	191,558	—	—	—	191,558
Derivative instruments	692,554	—	—	—	692,554
Other current assets	5,348	1	518	(1)	5,866
Total current assets	1,022,830	1	248,356	(19,027)	1,252,160
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,060,936	—	—	—	2,060,936
Proved properties	6,515,221	—	—	—	6,515,221
Fresh water distribution systems	421,012	—	—	—	421,012
Gathering systems and facilities	16,532	—	1,180,707	—	1,197,239
Other property and equipment	37,687	—	—	—	37,687
	9,051,388	—	1,180,707	—	10,232,095
Less accumulated depletion, depreciation, and amortization	(828,533)	—	(51,110)	—	(879,643)
Property and equipment, net	8,222,855	—	1,129,597	—	9,352,452
Derivative instruments	899,997	—	—	—	899,997
Investments in subsidiaries	137,423	—	—	(137,423)	—
Other assets, net	51,718	—	17,168	—	68,886
Total assets	$ 10,334,823	1	1,395,121	(156,450)	11,573,495
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 485,628	—	45,936	—	531,564
Intercompany payable	17,646	—	1,380	(19,026)	—
Accrued liabilities	163,268	—	5,346	—	168,614
Revenue distributions payable	182,352	—	—	—	182,352
Deferred income tax liability	260,373	—	—	—	260,373
Other current liabilities	12,203	—	—	(1)	12,202
Total current liabilities	1,121,470	—	52,662	(19,027)	1,155,105
Long-term liabilities:					
Long-term debt	4,247,550	115,000	—	—	4,362,550
Deferred income tax liability	534,423	—	—	—	534,423
Other liabilities	47,587	—	—	—	47,587
Total liabilities	5,951,030	115,000	52,662	(19,027)	6,099,665
Equity:					
Stockholders' equity:					
Parent net investment	—	(114,999)	—	114,999	—
Partners' capital	—	—	1,342,459	(1,342,459)	—
Common stock	2,621	—	—	—	2,621
Additional paid-in capital	3,513,725	—	—	—	3,513,725

Accumulated earnings	867,447	—	—	—	867,447
Total stockholders' equity	4,383,793	(114,999)	1,342,459	(1,227,460)	4,383,793
Noncontrolling interest in consolidated subsidiary	—	—	—	1,090,037	1,090,037
Total equity	4,383,793	(114,999)	1,342,459	(137,423)	5,473,830
Total liabilities and equity	$ 10,334,823	1	1,395,121	(156,450)	11,573,495

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

Condensed Consolidating Balance Sheet
June 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 30,419	—	112,867	—	143,286
Accounts receivable, net	79,190	—	—	—	79,190
Intercompany receivables	1,430	—	18,675	(20,105)	—
Accrued revenue	125,467	—	—	—	125,467
Derivative instruments	664,417	—	—	—	664,417
Other current assets	4,610	1	209	(1)	4,819
Total current assets	905,533	1	131,751	(20,106)	1,017,179
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,080,491	—	—	—	2,080,491
Proved properties	7,462,080	—	—	—	7,462,080
Fresh water distribution systems	441,692	—	—	—	441,692
Gathering systems and facilities	16,555	—	1,325,106	—	1,341,661
Other property and equipment	42,842	—	—	—	42,842
	10,043,660	—	1,325,106	—	11,368,766
Less accumulated depletion, depreciation, and amortization	(1,158,207)	—	(80,782)	—	(1,238,989)
Property and equipment, net	8,885,453	—	1,244,324	—	10,129,777
Derivative instruments	1,305,392	—	—	—	1,305,392
Investments in subsidiaries	102,456	—	—	(102,456)	—
Other assets, net	63,310	—	16,823	—	80,133
Total assets	$11,262,144	1	1,392,898	(122,562)	12,532,481
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 296,114	—	30,524	—	326,638
Intercompany payable	18,675	—	1,430	(20,105)	—
Accrued liabilities	168,283	—	15,036	—	183,319
Revenue distributions payable	190,881	—	—	—	190,881
Deferred income tax liability	251,097	—	—	—	251,097
Other current liabilities	14,249	—	—	(1)	14,248
Total current liabilities	939,299	—	46,990	(20,106)	966,183
Long-term liabilities:					
Long-term debt	4,347,038	153,000	—	—	4,500,038
Deferred income tax liability	706,948	—	—	—	706,948
Derivative instruments	651	—	—	—	651
Other liabilities	49,215	—	—	—	49,215
Total liabilities	6,043,151	153,000	46,990	(20,106)	6,223,035
Equity:					
Stockholders' equity:					
Parent net investment	—	(152,999)	—	152,999	—
Partners' capital	—	—	1,345,908	(1,345,908)	—
Common stock	2,770	—	—	—	2,770
Additional paid-in capital	4,099,718	—	—	—	4,099,718

Accumulated earnings	1,116,505	—	—	—	1,116,505
Total stockholders' equity	5,218,993	(152,999)	1,345,908	(1,192,909)	5,218,993
Noncontrolling interest in consolidated subsidiary	—	—	—	1,090,453	1,090,453
Total equity	5,218,993	(152,999)	1,345,908	(102,456)	6,309,446
Total liabilities and equity	$11,262,144	1	1,392,898	(122,562)	12,532,481

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

Condensed Consolidating Statement of Operations and Comprehensive Income
Three months ended June 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:					
Natural gas sales	$ 242,065	—	—	—	242,065
Natural gas liquids sales	59,525	—	—	—	59,525
Oil sales	23,032	—	—	—	23,032
Gathering, compression, and water distribution	1,826	—	56,593	(53,929)	4,490
Marketing	49,829	—	—	—	49,829
Commodity derivative fair value losses	(2,227)	—	—	—	(2,227)
Fee income	224	—	—	(224)	—
Total revenue	374,274	—	56,593	(54,153)	376,714
Operating expenses:					
Lease operating	6,673	—	—	—	6,673
Gathering, compression, processing, and transportation	213,560	—	7,105	(53,996)	166,669
Production and ad valorem taxes	18,332	—	4,187	—	22,519
Marketing	79,053	—	—	—	79,053
Exploration	628	—	—	—	628
Impairment of unproved properties	26,339	—	—	—	26,339
Depletion, depreciation, and amortization	161,955	—	15,091	—	177,046
Accretion of asset retirement obligations	408	—	—	—	408
General and administrative	49,431	—	9,917	(157)	59,191
Contract termination and rig stacking	1,937	—	—	—	1,937
Total operating expenses	558,316	—	36,300	(54,153)	540,463
Operating income (expense)	(184,042)	—	20,293	—	(163,749)
Other income (expenses):					
Interest	(58,980)	—	(843)	—	(59,823)
Equity in net income of subsidiaries	13,560	—	—	(13,560)	—
Total other expenses	(45,420)	—	(843)	(13,560)	(59,823)
Income (loss) before income taxes	(229,462)	—	19,450	(13,560)	(223,572)
Provision for income tax benefit	84,089	—	—	—	84,089
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(145,373)	—	19,450	(13,560)	(139,483)
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	5,890	5,890
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (145,373)	—	19,450	(19,450)	(145,373)

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

Condensed Consolidating Statement of Operations and Comprehensive Income
Six months ended June 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:					
Natural gas sales	$ 557,007	—	—	—	557,007
Natural gas liquids sales	138,311	—	—	—	138,311
Oil sales	35,489	—	—	—	35,489
Gathering, compression, and water distribution	5,693	—	108,836	(103,871)	10,658
Marketing	107,609	—	—	—	107,609
Commodity derivative fair value gains	757,327	—	—	—	757,327
Fee income	500	—	—	(500)	—
Total revenue	1,601,936	—	108,836	(104,371)	1,606,401
Operating expenses:					
Lease operating	14,775	—	—	—	14,775
Gathering, compression, processing, and transportation	419,239	—	15,093	(104,001)	330,331
Production and ad valorem taxes	38,849	—	7,888	—	46,737
Marketing	152,402	—	—	—	152,402
Exploration	1,999	—	—	—	1,999
Impairment of unproved properties	34,916	—	—	—	34,916
Depletion, depreciation, and amortization	329,673	—	29,673	—	359,346
Accretion of asset retirement obligations	808	—	—	—	808
General and administrative	99,192	—	19,418	(370)	118,240
Contract termination and rig stacking	10,902	—	—	—	10,902
Total operating expenses	1,102,755	—	72,072	(104,371)	1,070,456
Operating income	499,181	—	36,764	—	535,945
Other income (expenses):					
Interest	(111,342)	—	(1,666)	—	(113,008)
Equity in net income of subsidiaries	24,468	—	—	(24,468)	—
Total other expenses	(86,874)	—	(1,666)	(24,468)	(113,008)
Income before income taxes	412,307	—	35,098	(24,468)	422,937
Provision for income tax expense	(163,249)	—	—	—	(163,249)
Net income and comprehensive income including noncontrolling interest	249,058	—	35,098	(24,468)	259,688
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	10,630	10,630
Net income and comprehensive income attributable to Antero Resources Corporation	$ 249,058	—	35,098	(35,098)	249,058

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2014 and June 30, 2015

Condensed Consolidating Statement of Cash Flows
Six months ended June 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 506,317	—	84,278	—	590,595
Cash flows used in investing activities:					
Additions to unproved properties	(131,683)	—	—	—	(131,683)
Drilling and completion costs	(1,009,421)	—	—	—	(1,009,421)
Additions to fresh water distribution systems	(34,076)	—	—	—	(34,076)
Additions to gathering systems and facilities	(40,247)	—	(159,798)	—	(200,045)
Additions to other property and equipment	(2,794)	—	—	—	(2,794)
Change in other assets	(633)	—	(126)	—	(759)
Distributions from guarantor subsidiary	38,000	—	—	(38,000)	—
Distributions from non-guarantor subsidiary	29,043	—	—	(29,043)	—
Proceeds from asset sales	40,000	—	—	—	40,000
Net cash used in investing activities	(1,111,811)	—	(159,924)	(67,043)	(1,338,778)
Cash flows provided by (used in) financing activities:					
Issuance of common stock	537,693	—	—	—	537,693
Issuance of senior notes	750,000	—	—	—	750,000
Borrowings (repayments) on bank credit facility, net	(650,000)	38,000	—	—	(612,000)
Payments of deferred financing costs	(15,235)	—	(19)	—	(15,254)
Distributions	—	(38,000)	(41,660)	67,043	(12,617)
Other	(2,332)	—	—	—	(2,332)
Net cash provided by (used in) financing activities	620,126	—	(41,679)	67,043	645,490
Net increase (decrease) in cash and cash equivalents	14,632	—	(117,325)	—	(102,693)
Cash and cash equivalents, beginning of period	15,787	—	230,192	—	245,979
Cash and cash equivalents, end of period	$ 30,419	—	112,867	—	143,286

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our condensed consolidated financial statements and related notes included elsewhere in this report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in natural gas, NGLs, and oil prices, the timing of planned capital expenditures, our ability to fund our development programs, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." Also, see the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors." We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

In this section, references to "Antero Resources," "the Company," "we," "us," and "our" refer to Antero Resources Corporation and its subsidiaries, unless otherwise indicated or the context otherwise requires.

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to profitably grow our reserves and production, primarily on our existing multi-year project inventory of drilling locations.

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. As of June 30, 2015, we held approximately 559,000 net acres of rich gas and dry gas properties located in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. Our corporate headquarters are in Denver, Colorado.

We believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are operating, or are currently under construction, in each of our core operating areas to accommodate our current development plans.

We operate in the following industry segments: (i) the exploration, development and production of natural gas, NGLs, and oil; (ii) gathering and compression; (iii) fresh water distribution; and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are at 1615 Wynkoop Street, Denver, Colorado 80202. Our telephone number is (303) 357-7310. Our website is located at *www.anteroresources.com*.

We make available our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K. These documents are located *www.anteroresources.com* under the "Investors Relations" link.

Information on our website is not incorporated into this Quarterly Report on Form 10-Q or our other filings with the SEC and is not a part of them.

2015 Developments and Highlights

Energy Industry Environment

In late 2014, global energy commodity prices declined precipitously as a result of several factors, including an increase in worldwide commodity supplies, a stronger U.S. dollar, relatively mild weather in large portions of the U.S. during winter months, and

strong competition among oil producing countries for market share. Commodity prices have continued to remain low through the second quarter of 2015; prices for West Texas Intermediate have remained at or below $60 per Bbl, and Henry Hub natural gas prices have remained below $3.00 per MMBtu. In response to these market conditions and concerns about access to capital markets, many U.S. exploration and development companies significantly reduced their capital spending plans for 2015. Our capital budget for 2015 is $1.8 billion (exclusive of the capital budget for Antero Midstream Partners LP, or "Antero Midstream"), a 49% reduction from our 2014 capital expenditures. We plan to operate an average of 14 drilling rigs in 2015 as compared to an average of 21 rigs in 2014, and we plan to complete 130 horizontal wells in the Marcellus and Utica Shales in 2015 as compared to 177 in 2014. Additionally, we have deferred 50 Marcellus completions until the first half of 2016. We believe that our 2015 capital budget will be fully funded through operating cash flows and available borrowing capacity under our revolving credit facility. We will continue to monitor commodity prices and may revise the capital budget if conditions warrant.

Production and Financial Results

For the three months ended June 30, 2015, we generated cash flow from operations of $239 million, a net loss of $145 million, and Adjusted EBITDAX of $268 million. This compares to cash flow from operations of $224 million, a net loss of $42 million, and Adjusted EBITDAX of $266 million for the three months ended June 30, 2014. The loss of $145 million for the three months ended June 30, 2015 included $2 million of commodity derivative fair value losses (net of $196 million of settled derivative gains), deferred tax benefit of $84 million, and a noncash charge of $28 million for equity-based compensation. See "—Non-GAAP Financial Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

For the six months ended June 30, 2015, we generated cash flow from operations of $591 million, net income of $249 million, and Adjusted EBITDAX of $623 million. This compares to cash flow from operations of $498 million, a net loss of $137 million, and Adjusted EBITDAX of $540 million for the six months ended June 30, 2014. Net income of $249 million for the six months ended June 30, 2015 included $757 million of commodity derivative fair value gains, including $381 million of settled derivative gains, deferred tax expense of $163 million, and a noncash charge of $55 million for equity-based compensation. See "—Non-GAAP Financial Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

For the three months ended June 30, 2015, our production totaled approximately 135 Bcfe, or 1,484 MMcfe per day, a 67% increase compared to 81 Bcfe, or 891 MMcfe per day, for the three months ended June 30, 2014. The average price received for production for the three months ended June 30, 2015 was $2.40 per Mcfe before the effects of settled commodity hedges compared to $5.30 per Mcfe for the three months ended June 30, 2014. Average prices after the effects of settled commodity hedges were $3.85 per Mcfe for the three months ended June 30, 2015 compared to $5.31 per Mcfe for the three months ended June 30, 2014.

For the six months ended June 30, 2015, our production totaled approximately 269 Bcfe, or 1,485 MMcfe per day, a 77% increase compared to 152 Bcfe, or 838 MMcfe per day, for the six months ended June 30, 2014. The average price received for production for the six months ended June 30, 2015 was $2.72 per Mcfe before the effects of settled commodity hedges compared to $5.54 per Mcfe for the six months ended June 30, 2014. Average prices after the effects of settled commodity hedges were $4.14 per Mcfe for the six months ended June 30, 2015 compared to $5.53 per Mcfe for the six months ended June 30, 2014.

2015 Capital Budget

For the six months ended June 30, 2015, our consolidated capital expenditures were approximately $1.4 billion, including drilling and completion costs of $1.0 billion, gathering and compression project costs of $200 million, fresh water distribution system costs of $34 million, leasehold acquisition costs of $132 million, and other capital expenditures of $3 million. Antero's capital budget for 2015 is $1.8 billion and includes $1.6 billion for drilling and completion, $50 million for fresh water distribution infrastructure, and $150 million for core leasehold acquisitions. We do not budget for producing property acquisitions. Substantially all of the $1.6 billion allocated for drilling and completion is allocated to our operated drilling in liquids-rich gas areas. Approximately 60% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 40% is allocated to the Utica Shale. During 2015, we plan to operate an average of nine drilling rigs in the Marcellus Shale and five drilling rigs in the Utica Shale. Additionally, the capital budget for Antero Midstream for 2015 is a range of $425 million to $450 million. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Credit Facilities

The current borrowing base under our revolving credit facility is $4.0 billion and lender commitments are $4.0 billion. The borrowing base under our revolving credit facility is redetermined semi-annually and is based on the lenders' judgment of the volume of our proved oil and gas reserves, the estimated future cash flows from these reserves, and the values of our commodity hedge positions. The next redetermination is scheduled to occur in October 2015. At June 30, 2015, we had $1.12 billion of borrowings and $475 million of letters of credit outstanding under the revolving credit facility. Our revolving credit facility matures in May 2019. See "—Debt Agreements and Contractual Obligations—Senior Secured Revolving Credit Facility" for a description of our revolving credit facility.

Our consolidated subsidiary, Antero Midstream, has a revolving credit facility agreement that provides for lender commitments of $1.0 billion. The facility will mature on November 10, 2019. Antero Midstream did not have any borrowings under this facility at June 30, 2015. See "—Debt Agreements and Contractual Obligations—Midstream Credit Facility" for a description of this revolving credit facility.

Hedge Position

As of June 30, 2015, we had entered into hedging contracts for July 1, 2015 through December 31, 2021 for 2.648 Tcf of our projected natural gas production at a weighted average index price of $4.06 per MMbtu, 552 MBbls of oil at a weighted average price of $65.26 per Bbl, and 700 million gallons of propane at a weighted average price of $0.60 per gallon. These hedging contracts include contracts for the remaining six months ended December 31, 2015 of approximately 213 Bcf of natural gas at a weighted average index price of $4.33 per Mcf, 552 MBbls of oil at $65.26 per Bbl, and 178 million gallons of propane at a weighted average price of $0.63 per gallon.

Results of Operations

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2015

The Company has four operating segments: (1) the exploration, development, and production of natural gas, NGLs, and oil; (2) gathering and compression; (3) fresh water distribution; and (4) marketing of excess firm transportation capacity. Revenues from the gathering and compression and fresh water distribution segments are primarily derived from intersegment transactions for services provided to our exploration and production segment. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties. The operating results and assets of the Company's reportable segments were as follows for the three months ended June 30, 2014 and 2015:

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2014:						
Sales and revenues:						
Third-party	$ 305,786	2,017	1,548	1,987	—	311,338
Intersegment	—	14,906	38,970	—	(53,876)	—
Total	$ 305,786	16,923	40,518	1,987	(53,876)	311,338
Operating expenses:						
Lease operating	$ 5,021	—	10,156	—	(10,156)	5,021
Gathering, compression, processing, and transportation	116,547	2,196	—	—	(14,906)	103,837
Depletion, depreciation, and amortization	93,057	8,656	3,441	—	—	105,154
General and administrative expense (before equity-based compensation)	21,348	3,290	1,245	—	—	25,883
Equity-based compensation expense	29,136	2,490	848	—	—	32,474
Other operating expenses	28,996	—	1,330	13,946	—	44,272
Total	294,105	16,632	17,020	13,946	(25,062)	316,641
Operating income (loss)	$ 11,681	291	23,498	(11,959)	(28,814)	(5,303)

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2015:						
Sales and revenues:						
Third-party	$ 322,395	2,664	1,826	49,829	—	376,714
Intersegment	277	53,929	28,836	—	(83,042)	—
Total	$ 322,672	56,593	30,662	49,829	(83,042)	376,714
Operating expenses:						
Lease operating	$ 6,477	—	5,851	—	(5,655)	6,673
Gathering, compression, processing, and transportation	213,560	7,105	—	—	(53,996)	166,669
Depletion, depreciation, and amortization	155,586	15,298	6,162	—	—	177,046
General and administrative expense (before equity-based compensation)	26,257	4,529	1,033	—	(210)	31,609
Equity-based compensation expense	20,985	5,388	1,209	—	—	27,582
Other operating expenses	46,866	4,187	778	79,053	—	130,884
Total	469,731	36,507	15,033	79,053	(59,861)	540,463
Operating income (loss)	$ (147,059)	20,086	15,629	(29,224)	(23,181)	(163,749)

The following tables set forth selected operating data for the three months ended June 30, 2014 compared to the three months ended June 30, 2015:

(in thousands)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2015	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 314,151	$ 242,065	$ (72,086)	(23)%
NGLs sales	79,768	59,525	(20,243)	(25)%
Oil sales	35,633	23,032	(12,601)	(35)%
Gathering, compression, and water distribution	3,565	4,490	925	26 %
Marketing	1,987	49,829	47,842	2,408 %
Commodity derivative fair value losses	(123,766)	(2,227)	121,539	(98)%
Total operating revenues	311,338	376,714	65,376	21 %
Operating expenses:				
Lease operating	5,021	6,673	1,652	33 %
Gathering, compression, processing, and transportation	103,837	166,669	62,832	61 %
Production and ad valorem taxes	21,358	22,519	1,161	5 %
Marketing	13,946	79,053	65,107	467 %
Exploration	6,703	628	(6,075)	(91)%
Impairment of unproved properties	1,956	26,339	24,383	1,247 %
Depletion, depreciation, and amortization	105,154	177,046	71,892	68 %
Accretion of asset retirement obligations	309	408	99	32 %
General and administrative (before equity-based compensation)	25,883	31,609	5,726	22 %
Equity-based compensation	32,474	27,582	(4,892)	(15)%
Contract termination and rig stacking	—	1,937	1,937	*
Total operating expenses	316,641	540,463	223,822	71 %
Operating loss	(5,303)	(163,749)	(158,446)	*
Other Expenses:				
Interest expense	(37,260)	(59,823)	(22,563)	61 %
Loss on early extinguishment of debt	(20,386)	—	20,386	*
Total other expenses	(57,646)	(59,823)	(2,177)	4 %
Loss before income taxes	(62,949)	(223,572)	(160,623)	255 %
Income tax benefit	18,454	84,089	65,635	356 %
Loss from continuing operations	(44,495)	(139,483)	(94,988)	213 %
Income from discontinued operations	2,210	—	(2,210)	*
Net loss and comprehensive loss including noncontrolling interest	(42,285)	(139,483)	(97,198)	230 %
Net income and comprehensive income attributable to noncontrolling interest	—	5,890	5,890	*
Net loss and comprehensive loss attributable to Antero Resources Corporation	$ (42,285)	$ (145,373)	$ (103,088)	244 %
Adjusted EBITDAX (1)	$ 266,462	$ 268,192	$ 1,730	1 %

(1) See "—Non-GAAP Financial Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

* Not meaningful or applicable

	Three Months Ended June 30, 2014	2015	Amount of Increase (Decrease)	Percent Change
Production data:				
Natural gas (Bcf)	70	110	40	57 %
NGLs (MBbl)	1,451	3,655	2,204	152 %
Oil (MBbl)	391	523	132	34 %
Combined (Bcfe)	81	135	54	67 %
Daily combined production (MMcfe/d)	891	1,484	593	67 %
Average prices before effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 4.49	$ 2.20	$ (2.29)	(51)%
NGLs (per Bbl)	$ 54.98	$ 16.29	$ (38.69)	(70)%
Oil (per Bbl)	$ 91.20	$ 44.06	$ (47.14)	(52)%
Combined (per Mcfe)	$ 5.30	$ 2.40	$ (2.90)	(55)%
Average realized prices after effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 4.52	$ 3.86	$ (0.66)	(15)%
NGLs (per Bbl)	$ 54.98	$ 19.51	$ (35.47)	(65)%
Oil (per Bbl)	$ 87.31	$ 47.33	$ (39.98)	(46)%
Combined (per Mcfe)	$ 5.31	$ 3.85	$ (1.46)	(27)%
Average Costs (per Mcfe):				
Lease operating	$ 0.06	$ 0.05	$ (0.01)	(17)%
Gathering, compression, processing, and transportation	$ 1.28	$ 1.23	$ (0.05)	(4)%
Production and ad valorem taxes	$ 0.26	$ 0.17	$ (0.09)	(35)%
Marketing, net	$ 0.15	$ 0.22	$ 0.07	47 %
Depletion, depreciation, amortization, and accretion	$ 1.30	$ 1.31	$ 0.01	1 %
General and administrative (before equity-based compensation)	$ 0.32	$ 0.23	$ (0.09)	(28)%

(2) Average sales prices shown in the table reflect both of the before and after effects of our settled derivatives. Our calculation of such after effects includes realized gains or losses on settlements of commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

Discussion of Consolidated Results for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2015

Our gathering and compression, fresh water distribution, and marketing segments primarily support our exploration and production segment. The following discussion of our results consolidates those segments with our exploration and production segment.

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil decreased from $430 million for the three months ended June 30, 2014 to $325 million for the three months ended June 30, 2015, a decrease of $105 million, or 24%. Our production increased by 67% over that same period, from 81 Bcfe, or 891 MMcfe per day, for the three months ended June 30, 2014 to 135 Bcfe, or 1,484 MMcfe per day, for the three months ended June 30, 2015. Net equivalent prices before the effects of settled derivative gains decreased from $5.30 per Mcfe for the three months ended June 30, 2014 to $2.40 for the three months ended June 30, 2015, a decrease of 55%. Prices for natural gas, NGLs, and oil all declined from 2014 levels. Net equivalent prices after the effects of gains on settled derivatives decreased from $5.31 for the three months ended June 30, 2014 to $3.85 for the three months ended June 30, 2015.

Increased production volumes accounted for an approximate $286 million increase in year-over year product revenues (calculated as the change in year-to-year volumes times the prior year average price), and decreases in our equivalent prices accounted for an approximate $391 million decrease in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our active drilling program. Based on our current drilling and completion plans for the remainder of 2015, the increasing size of our production base, and the current commodity price environment, we expect the rate of growth in both our production and our product revenues to decline from the rates of growth realized in 2014.

Commodity derivative fair value losses. To achieve more predictable cash flows, and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas, NGLs, and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. For the three months ended June 30, 2014 and 2015, our hedges resulted in derivative fair value losses of $124 million and $2 million, respectively. The derivative fair value gains and losses included $1 million and $196 million of gains on settled derivatives for the three months ended June 30, 2014 and 2015, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. Derivative asset or liability positions at the end of any accounting period may reverse to the extent natural gas, NGLs, and oil strip prices increase or decrease from their levels at the end of the accounting period, or as gains or losses are realized through settlement. We expect continued volatility in commodity prices and the related fair value of our derivative instruments in the future.

Gathering, compression, and water distribution revenues. Gathering, compression, and water distribution revenues (net of intercompany eliminations of $54 million in 2014 and $83 million in 2015) remained consistent at $4 million for the three months ended June 30, 2014 and 2015. These amounts represent the portion of such fees that are charged to outside working interest owners in Company-operated wells, as well as fees charged to other third parties for water provided by the Company or usage of Antero Midstream's gathering pipelines.

Lease operating expenses. Lease operating expenses increased from $5 million (net of intercompany eliminations of $10 million) for the three months ended June 30, 2014 to $7 million (net of intercompany eliminations of $6 million) for the three months ended June 30, 2015, an increase of 33%. The increase is a result of an increase in the number of producing wells. On a per unit basis, lease operating expenses decreased from $0.06 per Mcfe for the three months ended June 30, 2014 to $0.05 for the three months ended June 30, 2015. Lease operating expenses are expected to slowly increase on a per unit basis as older properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $104 million (net of intercompany eliminations of $15 million) for the three months ended June 30, 2014 to $167 million (net of intercompany eliminations of $54 million) for the three months ended June 30, 2015. The increase in these expenses is a result of the increase in production, firm transportation commitments, and third-party gathering, compression, and processing expenses. On a per Mcfe basis, total gathering, compression, processing and transportation expenses decreased from $1.28 per Mcfe for the three months ended June 30, 2014 to $1.23 for the three months ended June 30, 2015 as a result of decreases in fuel costs as compared to the prior year period.

We have entered into contracts for significant firm transportation volumes in advance of having sufficient production to fully utilize the capacity. Based on current projections for our 2015 annual production levels, we estimate that we could incur total annual net marketing costs of $100 million to $150 million in 2015 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third party gas and capture positive basis differentials.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $21 million for the three months ended June 30, 2014 to $23 million for the three months ended June 30, 2015, primarily as a result of increased production and a larger midstream asset base subject to ad valorem taxes. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging increased from 5.0% for the three months ended June 30, 2014 to 6.9% for the three months ended June 30, 2015. Production and ad valorem taxes as a percentage of revenues increased primarily due to an increase in midstream assets subject to ad valorem taxes. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally drilled wells could increase our future production tax rates in Ohio if such legislation is enacted.

Exploration expense. Exploration expense of $7 million for the three months ended June 30, 2014 decreased to $1 million for the three months ended June 30, 2015 primarily because of an overall decrease in lease acquisition efforts, resulting in a decrease in unsuccessful lease acquisitions.

Impairment of unproved properties. Impairment of unproved properties increased from $2 million for the three months ended June 30, 2014 to $26 million for the three months ended June 30, 2015, primarily due to the impairment of a group of leases that we decided not to retain and develop. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks, or future plans to develop the acreage, and recognize impairment costs accordingly.

Depletion, depreciation, and amortization. Depletion, depreciation, and amortization ("DD&A") increased from $105 million for the three months ended June 30, 2014 to $177 million for the three months ended June 30, 2015, primarily because of increased production. DD&A per Mcfe increased by 1%, from $1.30 per Mcfe during the three months ended June 30, 2014 to $1.31 per Mcfe

during the three months ended June 30, 2015, primarily due to an increase in depreciation as a result of a larger base of midstream assets and facilities.

We evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas property to its estimated fair value. No impairment expenses were recorded for the three months ended June 30, 2014 and 2015 for proved properties.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased from $26 million for the three months ended June 30, 2014 to $32 million for the three months ended June 30, 2015, primarily as a result of increased staffing levels and related salary and benefits expenses, as well as increases in legal and other general corporate expenses, all of which are due to our increase in development activities and production levels. On a per unit basis, general and administrative expense before equity-based compensation decreased by 28%, from $0.32 per Mcfe during the three months ended June 30, 2014 to $0.23 per Mcfe during the three months ended June 30, 2015, primarily due to a 67% increase in production. We had 330 employees as of June 30, 2014 and 472 employees as of June 30, 2015.

Noncash equity-based compensation expense decreased from $32 million for the three months ended June 30, 2014 to $28 million for the three months ended June 30, 2015 as a result of a $12 million decrease in amortization of expense related to the vesting of profits interests, partially offset by a $8 million increase in equity-based compensation primarily related to restricted stock unit, stock option, and Antero Midstream phantom unit awards. See note 1 to the condensed consolidated financial statements included elsewhere in this report for more information on the vested profits interest charges.

Contract termination and rig stacking. Contract termination and rig stacking of $2 million during the three months ended June 30, 2015 represent fees incurred upon the delay or cancelation of drilling contracts with third-party contractors. We undertook these actions in order to align our drilling and completion activity level for the remainder of 2015 with our 2015 capital budget.

Interest expense. Interest expense increased from $37 million for the three months ended June 30, 2014 to $60 million for the three months ended June 30, 2015, primarily due to increased indebtedness. Interest expense includes approximately $2.0 million and $2.6 million of non-cash amortization of deferred financing costs for the three months ended June 30, 2014 and 2015, respectively.

Loss on early extinguishment of debt. On May 23, 2014, we redeemed our outstanding 7.25% senior notes due 2019. No debt retirements occurred during the three months ended June 30, 2015.

Income tax benefit. Income tax benefit increased from $18 million for the three months ended June 30, 2014 to $84 million for the three months ended June 30, 2015 because of the increase in the our pre-tax loss compared to the prior year period. The deferred benefit in 2014 and 2015 was due to the losses incurred for financial reporting purposes in the three months ended June 30, 2014 and June 30, 2015 and decreases our deferred tax liabilities. Equity-based compensation expense of $24 million and $12 million for the three months ended June 30, 2014 and 2015, respectively, related to the vested profits interests charges is not deductible for federal or state income taxes and, along with the effect of state taxes, largely accounts for the difference between the federal tax rate of 35% and the rate at which income tax benefit was recognized for the three months ended June 30, 2015.

At December 31, 2014, we had approximately $1.1 billion of U.S. federal net operating loss carryforwards ("NOLs") and approximately $1.0 billion of state NOLs, which expire from 2024 through 2034. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs. Such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that any such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at June 30, 2015 of $11 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. As of June 30, 2015, we have accrued approximately $1.4 million of interest on unrecognized tax benefits.

Adjusted EBITDAX. Adjusted EBITDAX increased from $266 million for the three months ended June 30, 2014 to $268 million for the three months ended June 30, 2015, an increase of 1%. The increase in Adjusted EBITDAX was primarily due to a 67% increase in production, which was offset by a 27% decrease in the average per Mcfe price received after the impact of settled derivatives, net of the related increases in cash operating and general and administrative expenses. See "—Non-GAAP Financial

Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) from continuing operations.

Discussion of Segment Results for the Three Months Ended June 30, 2014 Compared to the Three Months Ended June 30, 2015

Gathering and Compression. Revenue for the gathering and compression segment increased from $16.9 million for the three months ended June 30, 2014 to $56.6 million for the three months ended June 30, 2015, an increase of $39.7 million, or 234%. Gathering revenues increased by $32.6 million from the prior year period and compression revenues increased by $7.1 million as additional wells on production increased throughput volumes. Total operating expenses related to gathering and compression increased from $16.6 million for the three months ended June 30, 2014 to $36.5 million for the three months ended June 30, 2015 as a result of the increased throughput volumes, as well as increases in depreciation expense due to a larger base of gathering and compression assets.

Fresh Water Distribution. Revenue for the fresh water distribution segment decreased from $40.5 million for the three months ended June 30, 2014 to $30.7 million for the three months ended June 30, 2015, a decrease of $9.8 million, or 24%. The decrease was due to decreased use of the water systems in our hydraulic fracturing activities as a result of the deferral of some well completions until the latter part of 2015 and into 2016. The volume of water delivered through the system decreased from 11.4 MMBbls for the three months ended June 30, 2014 to 8.7 MMBbls for the three months ended June 30, 2015. Operating expenses for the fresh water distribution system decreased from $17.0 million for the three months ended June 30, 2014 to $15.0 million for the three months ended June 30, 2015 as a result of the decreased use of the water distribution systems.

Marketing. We purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity in order to optimize the revenues from these transportation agreements. Marketing revenues of $2 million and $50 million and expenses of $14 million and $79 million for the three months ended June 30, 2014 and 2015, respectively, relate to these activities. Net losses on our marketing activities were $12 million and $29 million for the three months ended June 30, 2014 and 2015, respectively. Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This includes firm transportation costs of $14 million and $30 million for the three months ended June 30, 2014 and 2015, respectively, related to unutilized excess capacity which increased due to new firm transportation agreements. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity to favorable markets.

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Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2015

The operating results and assets of the Company's reportable segments were as follows for the six months ended June 30, 2014 and 2015:

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2014:						
Sales and revenues:						
Third-party	$ 467,243	2,947	4,142	5,213	—	479,545
Intersegment	—	25,749	61,135	—	(86,884)	—
Total	$ 467,243	28,696	65,277	5,213	(86,884)	479,545
Operating expenses:						
Lease operating	$ 9,890	—	14,430	—	(14,430)	9,890
Gathering, compression, processing, and transportation	209,959	3,137	—	—	(25,749)	187,347
Depletion, depreciation, and amortization	175,237	14,764	6,359	—	—	196,360
General and administrative expense (before equity-based compensation)	39,470	5,753	2,508	—	—	47,731
Equity-based compensation expense	56,330	3,803	1,478	—	—	61,611
Other operating expenses	57,674	—	2,387	25,927	—	85,988
Total	548,560	27,457	27,162	25,927	(40,179)	588,927
Operating income (loss)	$ (81,317)	1,239	38,115	(20,714)	(46,705)	(109,382)

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2015:						
Sales and revenues:						
Third-party	$1,488,134	4,965	5,693	107,609	—	1,606,401
Intersegment	627	103,871	59,399	—	(163,897)	—
Total	$1,488,761	108,836	65,092	107,609	(163,897)	1,606,401
Operating expenses:						
Lease operating	$ 14,260	—	12,603	—	(12,088)	14,775
Gathering, compression, processing, and transportation	419,239	15,093	—	—	(104,001)	330,331
Depletion, depreciation, and amortization	317,091	29,973	12,282	—	—	359,346
General and administrative expense (before equity-based compensation)	51,670	9,407	2,295	—	(497)	62,875
Equity-based compensation expense	42,989	10,011	2,365	—	—	55,365
Other operating expenses	85,836	7,888	1,638	152,402	—	247,764
Total	931,085	72,372	31,183	152,402	(116,586)	1,070,456
Operating income (loss)	$ 557,676	36,464	33,909	(44,793)	(47,311)	535,945

The following tables set forth selected operating data for the six months ended June 30, 2014 compared to the six months ended June 30, 2015:

(in thousands)	Six Months Ended June 30, 2014	Six Months Ended June 30, 2015	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 626,487	$ 557,007	$ (69,480)	(11)%
NGLs sales	153,696	138,311	(15,385)	(10)%
Oil sales	59,755	35,489	(24,266)	(41)%
Gathering, compression, and water distribution	7,089	10,658	3,569	50 %
Marketing	5,213	107,609	102,396	1,964 %
Commodity derivative fair value gains (losses)	(372,695)	757,327	1,130,022	*
Total operating revenues	479,545	1,606,401	1,126,856	235 %
Operating expenses:				
Lease operating	9,890	14,775	4,885	49 %
Gathering, compression, processing, and transportation	187,347	330,331	142,984	76 %
Production and ad valorem taxes	42,397	46,737	4,340	10 %
Marketing	25,927	152,402	126,475	488 %
Exploration	13,700	1,999	(11,701)	(85)%
Impairment of unproved properties	3,353	34,916	31,563	941 %
Depletion, depreciation, and amortization	196,360	359,346	162,986	83 %
Accretion of asset retirement obligations	611	808	197	32 %
General and administrative (before equity-based compensation)	47,731	62,875	15,144	32 %
Equity-based compensation	61,611	55,365	(6,246)	(10)%
Contract termination and rig stacking	—	10,902	10,902	*
Total operating expenses	588,927	1,070,456	481,529	82 %
Operating income (loss)	(109,382)	535,945	645,327	*
Other Expenses:				
Interest expense	(68,602)	(113,008)	(44,406)	65 %
Loss on early extinguishment of debt	(20,386)	—	20,386	*
Total other expenses	(88,988)	(113,008)	(24,020)	27 %
Income (loss) before income taxes	(198,370)	422,937	621,307	*
Income tax (expense) benefit	59,116	(163,249)	(222,365)	*
Income (loss) from continuing operations	(139,254)	259,688	398,942	*
Income from discontinued operations	2,210	—	(2,210)	*
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(137,044)	259,688	396,732	*
Net income and comprehensive income attributable to noncontrolling interest	—	10,630	10,630	*
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (137,044)	$ 249,058	$ 386,102	*
Adjusted EBITDAX (1)	$ 540,118	$ 622,803	$ 82,685	15 %

(1) See "—Non-GAAP Financial Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

* Not meaningful or applicable

	Six Months Ended June 30, 2014		Six Months Ended June 30, 2015		Amount of Increase (Decrease)	Percent Change
Production data:						
Natural gas (Bcf)		132		222	90	68 %
NGLs (MBbl)		2,649		6,895	4,246	160 %
Oil (MBbl)		662		889	227	34 %
Combined (Bcfe)		152		269	117	77 %
Daily combined production (MMcfe/d)		838		1,485	647	77 %
Average prices before effects of derivative settlements(2):						
Natural gas (per Mcf)	$	4.75	$	2.51	$ (2.24)	(47)%
NGLs (per Bbl)	$	58.01	$	20.06	$ (37.95)	(65)%
Oil (per Bbl)	$	90.24	$	39.93	$ (50.31)	(56)%
Combined (per Mcfe)	$	5.54	$	2.72	$ (2.82)	(51)%
Average realized prices after effects of derivative settlements(2):						
Natural gas (per Mcf)	$	4.76	$	4.12	$ (0.64)	(13)%
NGLs (per Bbl)	$	58.01	$	22.66	$ (35.35)	(61)%
Oil (per Bbl)	$	88.73	$	46.40	$ (42.33)	(48)%
Combined (per Mcfe)	$	5.53	$	4.14	$ (1.39)	(25)%
Average Costs (per Mcfe):						
Lease operating	$	0.07	$	0.05	$ (0.02)	(29)%
Gathering, compression, processing, and transportation	$	1.23	$	1.23	$ —	— %
Production and ad valorem taxes	$	0.28	$	0.17	$ (0.11)	(39)%
Marketing, net	$	0.14	$	0.17	$ 0.03	21 %
Depletion, depreciation, amortization, and accretion	$	1.30	$	1.34	$ 0.04	3 %
General and administrative (before equity-based compensation)	$	0.31	$	0.23	$ (0.08)	(26)%

(2) Average sales prices shown in the table reflect both of the before and after effects of our settled derivatives. Our calculation of such after effects includes realized gains or losses on settlements of commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

Discussion of Consolidated Results for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2015

Our gathering and compression, fresh water distribution, and marketing segments primarily support our exploration and production segment. The following discussion of our results consolidates those segments with our exploration and production segment.

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil decreased from $840 million for the six months ended June 30, 2014 to $731 million for the six months ended June 30, 2015, a decrease of $109 million, or 13%. Our production increased by 77% over that same period, from 152 Bcfe, or 838 MMcfe per day, for the six months ended June 30, 2014 to 269 Bcfe, or 1,485 MMcfe per day, for the six months ended June 30, 2015. Net equivalent prices before the effects of settled derivative gains decreased from $5.54 per Mcfe for the six months ended June 30, 2014 to $2.72 for the six months ended June 30, 2015, a decrease of 51%. Prices for natural gas, NGLs, and oil all declined from 2014 levels. Net equivalent prices after the effects of gains on settled derivatives decreased from $5.53 for the six months ended June 30, 2014 to $4.14 for the six months ended June 30, 2015.

Increased production volumes accounted for an approximate $648 million increase in year-over year product revenues (calculated as the change in year-to-year volumes times the prior year average price), and decreases in our equivalent prices accounted for an approximate $757 million decrease in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our active drilling program. Based on our current drilling and completion plans for the remainder of 2015, the increasing size of our production base, and the current commodity price environment, we expect the rate of growth in both our production and our product revenues to decline from the rates of growth realized in 2014.

Commodity derivative fair value gains (losses). To achieve more predictable cash flows, and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas, NGLs, and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. For the six months ended June 30, 2014 and 2015, our hedges resulted in derivative fair value gains (losses) of $(373) million and $757 million, respectively. The derivative fair value gains and losses included $(0.1) million and $381 million of gains (losses) on settled derivatives for the six months ended June 30, 2014 and 2015, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. Derivative asset or liability positions at the end of any accounting period may reverse to the extent natural gas, NGLs, and oil strip prices increase or decrease from their levels at the end of the accounting period, or as gains or losses are realized through settlement. We expect continued volatility in commodity prices and the related fair value of our derivative instruments in the future.

Gathering, compression, and water distribution revenues. Gathering, compression, and water distribution fees increased from $7 million (net of intercompany eliminations of $87 million) for the six months ended June 30, 2014 to $11 million (net of intercompany eliminations of $163 million) for the six months ended June 30, 2015 primarily due to increased throughput from production. These amounts represent the portion of such fees that are charged to outside working interest owners in Company-operated wells, as well as fees charged to other third parties for water provided by the Company or usage of Antero Midstream's gathering pipelines.

Lease operating expenses. Lease operating expenses increased from $10 million (net of intercompany eliminations of $14 million) for the six months ended June 30, 2014 to $15 million (net of intercompany eliminations of $12 million) for the six months ended June 30, 2015, an increase of 49%. The increase is a result of an increase in the number of producing wells. On a per unit basis, lease operating expenses decreased from $0.07 per Mcfe for the six months ended June 30, 2014 to $0.05 for the six months ended June 30, 2015. Lease operating expenses are expected to slowly increase on a per unit basis as older properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $187 million (net of intercompany eliminations of $26 million) for the six months ended June 30, 2014 to $330 million (net of intercompany eliminations of $104 million) for the six months ended June 30, 2015. The increase in these expenses is a result of the increase in production, firm transportation commitments, and third-party gathering, compression, and processing expenses. On a per Mcfe basis, total gathering, compression, processing and transportation expenses remained consistent at $1.23 per Mcfe for the six months ended June 30, 2014 and 2015.

We have entered into contracts for significant firm transportation volumes in advance of having sufficient production to fully utilize the capacity. Based on current projections for our 2015 annual production levels, we estimate that we could incur total annual marketing expense of $100 million to $150 million in 2015 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third party gas and capture positive basis differentials.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $42 million for the six months ended June 30, 2014 to $47 million for the six months ended June 30, 2015, primarily as a result of increased production and a larger midstream asset base subject to ad valorem taxes. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging increased from 5.0% for the six months ended June 30, 2014 to 6.4% for the six months ended June 30, 2015. Production and ad valorem taxes as a percentage of revenues increased primarily due to an increase in midstream assets subject to ad valorem taxes. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally drilled wells could increase our future production tax rates in Ohio if such legislation is enacted.

Exploration expense. Exploration expense of $14 million for the six months ended June 30, 2014 decreased to $2 million for the six months ended June 30, 2015 primarily because of an overall decrease in lease acquisition efforts, resulting in a decrease in unsuccessful lease acquisitions.

Impairment of unproved properties. Impairment of unproved properties increased from $3 million for the six months ended June 30, 2014 to $35 million for the six months ended June 30, 2015, primarily due to the impairment of a group of leases that we decided not to retain and develop. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks, or future plans to develop the acreage, and recognize impairment costs accordingly.

DD&A. DD&A increased from $196 million for the six months ended June 30, 2014 to $359 million for the six months ended June 30, 2015, primarily because of increased production. DD&A per Mcfe increased by 3%, from $1.30 per Mcfe during the six months ended June 30, 2014 to $1.34 per Mcfe during the six months ended June 30, 2015, primarily due to an increase in depreciation as a result of a larger base of midstream assets and facilities.

We evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the six months ended June 30, 2014 and 2015 for proved properties.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased from $48 million for the six months ended June 30, 2014 to $63 million for the six months ended June 30, 2015, primarily as a result of increased staffing levels and related salary and benefits expenses, as well as increases in legal and other general corporate expenses, all of which are due to our increase in development activities and production levels. On a per unit basis, general and administrative expense before equity-based compensation decreased by 26%, from $0.31 per Mcfe during the six months ended June 30, 2014 to $0.23 per Mcfe during the six months ended June 30, 2015, primarily due to a 77% increase in production. We had 330 employees as of June 30, 2014 and 472 employees as of June 30, 2015.

Noncash equity-based compensation expense decreased from $62 million for the six months ended June 30, 2014 to $55 million for the six months ended June 30, 2015 as a result of a $26 million decrease in amortization of expense related to the vesting of profits interests, partially offset by a $19 million increase in equity-based compensation primarily related to restricted stock unit, stock option, and Antero Midstream phantom unit awards. See note 1 to the condensed consolidated financial statements included elsewhere in this report for more information on the vested profits interest charges.

Contract termination and rig stacking. Contract termination and rig stacking of $11 million during the six months ended June 30, 2015 represent fees incurred upon the delay or cancelation of drilling contracts with third-party contractors. We undertook these actions in order to align our drilling and completion activity level for the remainder of 2015 with our 2015 capital budget.

Interest expense. Interest expense increased from $69 million for the six months ended June 30, 2014 to $113 million for the six months ended June 30, 2015, primarily due to increased indebtedness. Interest expense includes approximately $3.7 million and $4.8 million of non-cash amortization of deferred financing costs for the six months ended June 30, 2014 and 2015, respectively.

Loss on early extinguishment of debt. On May 23, 2014, we redeemed our outstanding 7.25% senior notes due 2019. No debt retirements occurred during the six months ended June 30, 2015.

Income tax expense. Income tax expense changed from a deferred tax benefit of $59 million for the six months ended June 30, 2014 to a deferred tax expense of $163 million for the six months ended June 30, 2015. The deferred tax benefit for the six months ended June 30, 2014 was due to a pre-tax loss incurred for financial reporting purposes, whereas we had pre-tax income for the six months ended June 30, 2015. Equity-based compensation expense of $53 million and $27 million for the six months ended June 30, 2014 and 2015, respectively, related to the vested profits interests charges is not deductible for federal or state income taxes and, along with the effect of state taxes, largely accounts for the difference between the federal tax rate of 35% and the rates at which income tax expense was provided for the six months ended June 30, 2015.

At December 31, 2014, we had approximately $1.1 billion of U.S. federal NOLs and approximately $1.0 billion of state NOLs, which expire from 2024 through 2034. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs. Such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that any such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at June 30, 2015 of $11 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. As of June 30, 2015, we have accrued approximately $1.4 million of interest on unrecognized tax benefits.

Adjusted EBITDAX. Adjusted EBITDAX increased from $540 million for the six months ended June 30, 2014 to $623 million for the six months ended June 30, 2015, an increase of 15%. The increase in Adjusted EBITDAX was primarily due to a 77% increase in production, which was partially offset by a 25% decrease in the average per Mcfe price received after the impact of settled derivatives, net of the related increases in cash operating and general and administrative expenses. See "—Non-GAAP Financial Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) from continuing operations.

Discussion of Segment Results for the Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2015

Gathering and Compression. Revenue for the gathering and compression segment increased from $29 million for the six months ended June 30, 2014 to $109 million for the six months ended June 30, 2015, an increase of $80 million, or 279%. Gathering revenues increased by $68 million from the prior year period and compression revenues increased by $12 million as additional wells on production increased throughput volumes. Total operating expenses related to gathering and compression increased from $27 million for the six months ended June 30, 2014 to $72 million for the six months ended June 30, 2015 as a result of the increased throughput volumes, as well as increases in depreciation expense due to a larger base of gathering and compression assets.

Fresh Water Distribution. Revenue for the fresh water distribution segment remained consistent at $65 million for the six months ended June 30, 2014 and 2015. The volume of water delivered through the system decreased from 18.3 MMBbls for the six months ended June 30, 2014 to 17.9 MMBbls for the six months ended June 30, 2015. Operating expenses for the fresh water distribution system increased from $27 million for the six months ended June 30, 2014 to $31 million for the six months ended June 30, 2015 as a result of an increase in depreciation expense due to a larger base of water distribution assets.

Marketing. We purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity in order to optimize the revenues from these transportation agreements. Marketing revenues of $5 million and $108 million and expenses of $26 million and $152 million for the six months ended June 30, 2014 and 2015, respectively, relate to these activities. Net losses on our marketing activities were $21 million and $44 million for the six months ended June 30, 2014 and 2015, respectively. Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This includes firm transportation costs of $26 million and $45 million for the six months ended June 30, 2014 and 2015, respectively, related to unutilized excess capacity which increased due to new firm transportation agreements. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity to favorable markets.

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt and equity securities, borrowings under our revolving credit facility, asset sales, and net cash provided by operating activities. During the six months ended June 30, 2015, we raised capital through the issuance of $750 million of 5.625% senior notes due 2023 and an offering of our common stock which resulted in net proceeds of approximately $538 million. Historically, our primary use of cash has been for the exploration, development, and acquisition of natural gas, NGLs, and oil properties, as well as for the development of gathering, compression, and fresh water distribution system infrastructure. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities, and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us.

We believe that funds from operating cash flows and available borrowings under our revolving credit facility will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "—Debt Agreements and Contractual Obligations."

The following table summarizes our cash flows for the six months ended June 30, 2014 and 2015:

(in thousands)	Six Months Ended June 30, 2014	Six Months Ended June 30, 2015
Net cash provided by operating activities	$ 498,029	$ 590,595
Net cash used in investing activities	(1,753,871)	(1,338,778)
Net cash provided by financing activities	1,257,628	645,490
Net increase (decrease) in cash and cash equivalents	$ 1,786	$ (102,693)

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $498 million and $591 million for the six months ended June 30, 2014 and 2015, respectively. The increase in cash flows from operations from the six months ended June 30, 2014 to the six months ended June 30, 2015 was primarily the result of increased combined revenues from oil and gas production and settled derivatives, net of increases in cash operating costs, interest expense, and changes in working capital levels.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of natural gas, NGLs, and oil prices. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets, and other variables influence the market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk" below.

Cash Flow Used in Investing Activities

During the six months ended June 30, 2015, we used cash totaling $1.3 billion in investing activities, including $1.0 billion for drilling and completion costs, $132 million for undeveloped leasehold acquisitions, $34 million for fresh water distribution facilities, $200 million for gathering and compression systems (through Antero Midstream), and $3 million for other property and equipment. These expenditures were partially offset by the receipt of $40 million attributable to final purchase price adjustments from the sale of a gathering system in 2012. During the six months ended June 30, 2014, we used cash totaling $1.8 billion in investing activities, including $1.1 billion for drilling and completion costs, $239 million for undeveloped leasehold acquisitions, $100 million for fresh water distribution systems, $262 million for gathering and compression systems and $11 million for other property and equipment.

Our board of directors has approved a capital budget of $1.8 billion for 2015, which does not include the capital budget of $425 million to $450 million for Antero Midstream, our consolidated subsidiary. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity, and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow, and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2015 of $645 million consisted of the issuance of $750 million of our 5.625% Senior Notes due 2023 and net proceeds of $538 million from the issuance of common stock, partially offset by net repayments on our revolving credit facility of $612 million and other items totaling $31 million. Net cash provided by financing activities of $1.3 billion for the six months ended June 30, 2014 consisted of net additional borrowings on our revolving credit facility of $952 million and the issuance of $600 million of our 5.125% Senior Notes due 2022, net of $294 million for retirements of senior notes and payments for early redemption premiums and deferred financing costs.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility. We have a senior secured revolving bank credit facility (the "Credit Facility") with a consortium of bank lenders. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our proved properties and commodity hedge positions and are subject to regular semiannual redeterminations. At June 30, 2015, the borrowing base was $4.0 billion and lender commitments were $4.0 billion, including $200 million of commitments under the Water Facility described below. The next redetermination of the borrowing base is scheduled to occur in October 2015. At June 30, 2015, we had $1.12 billion of borrowings and $475 million of letters of credit outstanding under the Credit Facility and the Water Facility, with a weighted average interest rate of 2.07%. At December 31, 2014, we had $1.73 billion of borrowings and $387 million of letters of credit outstanding under the Credit Facility and the Water Facility, with a weighted average interest rate of 2.06%. The Credit Facility matures on May 5, 2019.

On November 10, 2014, the Company and Antero Water, a wholly-owned subsidiary of the Company, entered into a new water credit facility (the "Water Facility") in order to provide for separate borrowings attributable to our fresh water distribution business. In accordance with the Credit Facility and the Water Facility agreements, borrowings under the Water Facility reduce availability under the Credit Facility on a dollar-for-dollar basis. The Water Facility will mature at the earlier of the sale of Antero Water to Antero Midstream, the sale of Antero Water's assets to Antero Midstream, or May 12, 2016.

Principal amounts borrowed on the Credit Facility and Water Facility are payable on the maturity dates with such borrowings bearing interest that is payable quarterly or, in the case of Eurodollar Rate Loans, at the end of the applicable interest period if shorter than three months. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per

annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points, and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized. The amounts outstanding under the Credit Facility are secured by a first priority lien on substantially all of our natural gas, NGLs, and oil properties and associated assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly-owned subsidiaries. The amounts outstanding under the Water Facility are secured by a first priority lien on substantially all of our water distribution assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly-owned subsidiaries. For information concerning the effect of changes in interest rates on interest payments under these facilities, see "Item 7A. Quantitative and Qualitative Disclosure About Market Risk."

The Credit Facility and Water Facility contain restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- pay dividends;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Credit Facility and Water Facility also require us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our consolidated current liabilities, of not less than 1.0 to 1.0 as of the end of each fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX to consolidated interest expense over the most recent four quarters, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2014 and June 30, 2015. The actual borrowing capacity available to us may be limited by these current ratio and minimum interest coverage ratio covenants. At June 30, 2015, our current ratio was 3.85 to 1.0 (based on the $4.0 billion borrowing base in effect as of June 30, 2015) and our interest coverage ratio was 6.05 to 1.0.

Midstream Credit Facility. On November 10, 2014, in connection with the closing of its IPO, Antero Midstream entered into a new revolving credit facility (the "Midstream Facility") among Antero Midstream, certain lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, and swing line lender. The Midstream Facility provides for lender commitments of $1.0 billion and for a letter of credit sublimit of $150 million. There were no borrowings or letters of credit outstanding under the Midstream Facility at December 31, 2014 and June 30, 2015. The Midstream Facility will mature on November 10, 2019.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly. Antero Midstream has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 225 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 125 basis points, depending on the leverage ratio then in effect.

The Midstream Facility is secured by mortgages on substantially all of Antero Midstream's and its restricted subsidiaries' properties – primarily assets used in the provision of gathering and compression services to the Company and third parties – and guarantees from its restricted subsidiaries. The Midstream Facility is not guaranteed by Antero. Interest is payable at a variable rate based on LIBOR or the prime rate based on Antero Midstream's election at the time of borrowing. The Midstream Facility contains restrictive covenants that may limit Antero Midstream's ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain restricted payments;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

Borrowings under the Midstream Facility also require Antero Midstream to maintain the following financial ratios:

- an interest coverage ratio, which is the ratio of Antero Midstream's consolidated EBITDA to its consolidated current interest charges of at least 2.5 to 1.0 at the end of each fiscal quarter; provided that upon obtaining an investment grade rating, the borrower may elect not to be subject to such ratio;
- a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 5.0 to 1.0; provided that after electing to issue unsecured high yield notes, the consolidated total leverage ratio will not be more than 5.25 to 1.0, or, following the election of the borrower for two fiscal quarters after a material acquisition, 5.50 to 1.0; and
- if Antero Midstream elects to issue unsecured high yield notes, a consolidated senior secured leverage ratio, which is the ratio of consolidated senior secured debt to consolidated EBITDA, of not more than 3.75 to 1.0.

Antero Midstream was in compliance with such covenants and ratios as of December 31, 2014 and June 30, 2015.

Senior Notes. We have $525 million of 6.00% senior notes outstanding, which are due December 1, 2020. The 2020 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2020 notes rank pari passu to our other outstanding senior notes. The 2020 notes are guaranteed on a senior unsecured basis by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2020 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2020 notes at any time on or after December 1, 2015 at redemption prices ranging from 104.50% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, we may redeem up to 35% of the aggregate principal amount of the 2020 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the 2020 notes, plus accrued interest. At any time prior to December 1, 2015, we may redeem the 2020 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2020 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control, the holders of the 2020 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2020 notes, plus accrued interest.

We also have $1.0 billion of 5.375% senior notes outstanding, which are due November 1, 2021. The 2021 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2021 notes rank parri passu to our other outstanding senior notes. The 2021 notes are guaranteed by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. We may redeem all or part of the 2021 notes at any time on or after November 1, 2016 at redemption prices ranging from 104.031% on or after November 1, 2016 to 100.00% on or after November 1, 2019. In addition, on or before November 1, 2016, we may redeem up to 35% of the aggregate principal amount of the 2021 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375%. At any time prior to November 1, 2016, we may also redeem the 2021 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2021 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control, we may be required to offer to purchase the 2021 notes from the holders at a price equal to 101% of the principal amount of the 2021 notes, plus accrued interest.

We also have $1.1 billion of 5.125% senior notes outstanding, which are due December 1, 2022. The 2022 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2022 notes rank parri passu to our other outstanding senior notes. The 2022 notes are guaranteed by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2022 notes at any time on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, we may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125%. At any time prior to June 1, 2017, we may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control prior to December 1, 2015, we may redeem all, but not less than all, of the 2022 notes at a redemption price equal to 110% of the principal amount of the 2022 notes. If we undergo a change of control, the holders of the 2022 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued interest.

We also have $750 million of 5.625% senior notes outstanding, which are due June 1, 2023. The 2023 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2023 notes rank parri passu to our other outstanding senior notes. The 2023 notes are guaranteed by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2023 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2023 notes at any time on or after June 1, 2018 at redemption prices ranging from 104.219% on or after June 1, 2018 to 100.00% on or after June 1, 2021. In addition, on or before June 1, 2018, we may redeem up to 35% of the aggregate principal amount of the 2023 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.625%. At any time prior to June 1, 2018, we may also redeem the 2023 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2023 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control prior to June 1, 2016, we may redeem all, but not less than all, of the 2023 notes at a redemption price equal to 110% of the principal amount of the 2023 notes. If we undergo a change of control, the holders of the 2023 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2023 notes, plus accrued interest.

We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under the Credit Facility, redeem previously issued senior notes, and for development of our oil and natural gas properties.

The senior notes indentures each contain restrictive covenants and restrict our ability to incur additional debt unless a pro forma minimum interest coverage ratio requirement of 2.25:1 is maintained. We were in compliance with such covenants as of December 31, 2014 and June 30, 2015.

Treasury Management Facility. We have a stand-alone revolving note with a lender under the Credit Facility which provides for up to $25 million of cash management obligations in order to facilitate our daily treasury management. Borrowings under the revolving note are secured by the collateral for the Credit Facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on May 1, 2016. At December 31, 2014 and June 30, 2015, there were no outstanding borrowings under this facility.

Contractual Obligations. A summary of our contractual obligations as of June 30, 2015 is provided in the following table.

	Year Ended June 30,						
(in millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**

Credit Facility and Water Facility(1)	$ —	—	—	1,118	—	—	1,118
Senior notes—principal(2)	—	—	—	—	—	3,375	3,375
Senior notes—interest(2)	184	184	184	184	184	337	1,257
Drilling rig and frac service commitments(3)	185	145	39	—	—	—	369
Firm transportation (4)	417	753	825	993	1,073	11,314	15,375
Gas processing, gathering, and compression services (5)	219	284	239	211	186	954	2,093
Office and equipment leases	10	9	8	5	3	9	44
Asset retirement obligations(6)	—	—	—	—	—	19	19
Total	$ 1,015	1,375	1,295	2,511	1,446	16,008	23,650

(1) Includes outstanding principal amounts at June 30, 2015. This table does not include future commitment fees, interest expense or other fees on our Credit Facility and Water Facility because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged.

(2) Includes the 6.00% notes due 2020, the 5.375% notes due 2021, the 5.125% notes due 2022, and the 5.625% notes due 2023.

(3) Includes contracts for the services of drilling rigs and hydraulic fracturing fleets, which expire at various dates from July 2015 through June 2018. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(4) Includes firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit us to transport minimum daily natural gas or NGLs volumes at negotiated rates, or pay for any deficiencies at specified reservation fee rates. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(5) Contractual commitments for gas processing, gathering and compression services agreements represent minimum commitments under long-term agreements. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(6) Represents the present value of our estimated asset retirement obligations. Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

Non-GAAP Financial Measure

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income (loss), including noncontrolling interests, before interest expense, interest income, derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), taxes, impairments, depletion, depreciation, amortization, and accretion, exploration expense, franchise taxes, equity-based compensation, loss on early extinguishment of debt, contract termination and rig stacking costs, and gain or loss on sale of assets. "Adjusted EBITDAX," as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing, and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting, and by our lenders pursuant to covenants under our revolving credit facility and the indentures governing our senior notes.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effects of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies, and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from continuing operations, including noncontrolling interests, to Adjusted EBITDAX from continuing operations, a reconciliation of our net income from discontinued operations to Adjusted EBITDAX from discontinued operations, and a reconciliation of our total Adjusted EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case, for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2014**	**2015**	**2014**	**2015**
Net income (loss) including noncontrolling interest	$ (44,495)	(139,483)	(139,254)	259,688
Commodity derivative fair value (gains) losses(1)	123,766	2,227	372,695	(757,327)
Gains (losses) on settled derivative instruments(1)	953	195,880	(118)	380,720
Interest expense	37,260	59,823	68,602	113,008
Loss on early extinguishment of debt	20,386	—	20,386	—
Income tax expense (benefit)	(18,454)	(84,089)	(59,116)	163,249
Depreciation, depletion, amortization, and accretion	105,463	177,454	196,971	360,154
Impairment of unproved properties	1,956	26,339	3,353	34,916
Exploration expense	6,703	628	13,700	1,999
Equity-based compensation expense	32,474	27,582	61,611	55,365
State franchise taxes	450	(106)	1,288	129
Contract termination and rig stacking	—	1,937	—	10,902
Consolidated Adjusted EBITDAX	266,462	268,192	540,118	622,803
Net income from discontinued operations	2,210	—	2,210	—
Gain on sale of assets	(3,564)	—	(3,564)	—
Income tax expense	1,354	—	1,354	—
Adjusted EBITDAX from discontinued operations	—	—	—	—
Total adjusted EBITDAX	266,462	268,192	540,118	622,803
Interest expense	(37,260)	(59,823)	(68,602)	(113,008)
Exploration expense	(6,703)	(628)	(13,700)	(1,999)
Changes in current assets and liabilities	3,886	30,894	40,532	89,831
State franchise taxes	(450)	106	(1,288)	(129)
Other noncash items	(2,213)	460	969	(6,903)
Net cash provided by operating activities	$ 223,722	239,201	498,029	590,595

(1) The adjustments for the derivative fair value (gains) losses and net cash received on settled commodity derivative instruments have the effect of adjusting net income (loss) from operations for changes in the fair value of unsettled derivative instruments, which are recognized at the end of each accounting period. As a result, commodity derivate gains and losses are reflected on a cash basis in the calculation of Adjusted EBITDAX for derivatives which settled during the period.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. Our more significant accounting policies and estimates include the successful efforts method of accounting for oil and gas production activities, estimates of natural gas and oil reserve quantities and standardized measures of future cash flows, and impairment of unproved properties. We provide an expanded discussion of our more significant accounting policies, estimates and judgments in our 2014 Form 10-K. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of our consolidated financial statements. Also, see note 2 of the notes to our audited consolidated financial statements, included in our 2014 Form 10-K, for a discussion of additional accounting policies and estimates made by management.

New Accounting Pronouncements

On May 28, 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers*, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective. The new standard becomes effective for the Company on January 1, 2018. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 will have on its consolidated financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

On April 7, 2015, the FASB issued ASU No. 2015-03, *Interest–Imputation of Interest*, which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the associated debt liability. The new standard becomes effective for the Company on January 1, 2016. The Company does not believe that this standard will have a material impact on its ongoing financial reporting upon adoption.

Off-Balance Sheet Arrangements

As of June 30, 2015, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rigs, hydraulic fracturing services, firm transportation, gas processing, and gathering and compression services. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for commitments under operating leases, drilling rig and hydraulic fracturing service agreements, firm transportation, gas processing, and gathering and compression service agreements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs, and oil prices, and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas, NGLs, and oil production. Realized pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production and the prevailing worldwide price for crude oil. Pricing for natural gas, NGLs, and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flow caused by changes in commodity prices, we enter into financial commodity swap contracts to receive fixed prices for a portion of our natural gas, NGLs, and oil production when management believes that favorable future prices can be secured. We hedge part of our natural gas production at fixed prices for our sales points to mitigate the risk of differentials to the sales point prices. Part of our production is also hedged at NYMEX prices.

Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas, NGLs, and oil price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. These contracts may include financial commodity price swaps whereby we receive a fixed price for our production and pay a variable market price to the contract counterparty, cashless price collars that set a floor and ceiling price for the hedged production, or basis differential swaps. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference. The Company was not party to any collars as of or during the six months ended June 30, 2015.

At June 30, 2015, we had in place natural gas, NGLs, and oil swaps covering portions of our projected production from 2015 through 2021. Our commodity hedge position as of June 30, 2015 is summarized in note 7 to our condensed consolidated financial statements included elsewhere herein. Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to price fluctuations. The Credit Facility allows us to hedge up to 75% of our projected production for the next five years, and 65% of our subsequent estimated proved reserves through December 31, 2021. Based on our production and our fixed price swap contracts in place during the six months ended June 30, 2015, our income before taxes would have decreased by approximately $4 million for each $0.10 decrease per MMBtu in natural gas prices and $1.00 decrease per Bbl in oil and NGLs prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception, are recorded at fair market value in accordance with U.S. GAAP and are included in our consolidated balance sheets as assets or liabilities. The fair values of our derivative instruments are adjusted for non-performance risk. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. We present total gains or losses on commodity derivatives (both cash-settled derivatives and derivative positions which remain open) in our operating revenues as "Commodity derivative fair value gains (losses)."

Mark-to-market adjustments of derivative instruments cause earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are only impacted when the associated derivative instrument contracts are settled by making or receiving payments to or from the counterparty. At June 30, 2015, the estimated fair value of our commodity derivative instruments was a net asset of $2.0 billion comprised of current and noncurrent assets and a noncurrent liability. At December 31, 2014, the estimated fair value of our commodity derivative instruments was a net asset of $1.6 billion comprised of current and noncurrent assets.

By removing price volatility from a portion of our expected production through December 2021, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flows in future periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($2.0 billion at June 30, 2015), the sale of our oil and gas production ($125 million at June 30, 2015) which we market to energy companies, and joint interest receivables ($79 million at June 30, 2015).

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions which management deems to be competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have commodity hedges in place with thirteen different counterparties, all of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately $2.0 billion at June 30, 2015 includes the following values by bank counterparty: Citigroup - $402 million; Barclays - $358 million; JP Morgan - $319 million; Morgan Stanley - $261 million; Wells Fargo - $231 million; BNP Paribas - $193 million; Scotiabank - $115 million; Toronto Dominion - $44 million; Fifth Third - $35 million; Canadian Imperial Bank of Commerce - $8 million; and Bank of Montreal - $3 million. The credit ratings of certain of these banks were downgraded in recent years because of the sovereign debt crisis in Europe. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at June 30, 2015 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our Credit Facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of June 30, 2015, we did not have any past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to the concentration of our receivables from several significant customers for sales of natural gas, NGLs, and oil. We generally do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us, or their insolvency or liquidation, may adversely affect our financial results.

Joint interest receivables arise from billing entities who own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we drill. We have minimal control over deciding who participates in our wells.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility and Water Facility, and the Midstream Facility of our subsidiary, Antero Midstream. Each of these credit facilities has a floating interest rate. The average annual interest rate incurred on this indebtedness during the June 30, 2015 was approximately 2.29%. A 1.0% increase in each of the applicable average interest rates for the six months ended June 30, 2015 would have resulted in an estimated $6.0 million increase in interest expense.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2015 at the reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings.

In March 2011, we received orders for compliance from federal regulatory agencies, including the U.S. Environmental Protection Agency (the "EPA") relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. We have responded to all pending orders and are actively cooperating with the relevant agencies. No fine or penalty relating to these matters has been proposed at this time, but we believe that these actions will result in monetary sanctions exceeding $100,000. We are unable to estimate the total amount of such monetary sanctions or costs to remediate these locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date, and management does not expect these matters to have a material adverse effect on our financial condition, results of operations, or cash flows.

We have received a Notice of Violation from the West Virginia Department of Environmental Protection ("WVDEP") related to a drilling incident that occurred in Doddridge County, West Virginia. While drilling a new well, we came into contact win an existing well, resulting in a release of methane gas and potential temporary impacts to groundwater. Groundwater monitoring to date has not identified any significant concerns related to this incident. We continue to work with the WVDEP to resolve this matter but believe it could result in monetary sanctions exceeding $100,000; however, we do not expect that any ultimate sanction would exceed $300,000.

We have been named in separate lawsuits in Colorado, West Virginia, Ohio, and Pennsylvania in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties and their persons. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. The Company denies any such allegations and intends to vigorously defend itself against these actions. We are unable to estimate the amount of monetary damages, if any, that might result from these claims.

The Company is the subject of two nearly identical lawsuits brought by South Jersey Gas Company and South Jersey Resources Group, LLC (collectively "SJGC") filed on February 4, 2015 in the Superior Court of New Jersey. The lawsuits have since been consolidated into one case. SJGC are purchasers of some of the Company's natural gas production under contracts entered into in 2011. Deliveries under the contracts began in October 2011 and the delivery obligation continues through October 2019. SJGC allege that the index prices specified in the contracts, and the index prices at which SJGC paid for deliveries from 2011 through September 2014, are no longer appropriate under the contracts because a market disruption event (as defined by the contract) has occurred and, as a result, a new index price is to be determined by the parties. The lawsuit seeks a reformation of the contracts, compensatory and punitive damages to be determined at trial, and costs and expenses of the actions. Beginning in October 2014, SJGC began paying the Company under indexes unilaterally selected by SJGC and not specified in the contract. The Company contends that no market disruption event has occurred and that SJGC has breached the contracts by failing to pay the Company based on the express price terms of the contracts. The Company further contends that jurisdiction and venue are improper in New Jersey. On March 30, 2015, the Company filed suit against SJGC in United States District Court in Colorado seeking relief for breach of contract, damages in the amounts that SJGC has short paid and continues to short pay, as well as costs of the suit. Through June 30, 2015, the Company estimates that it is owed approximately $22.5 million more than SJGC has paid using the indexes unilaterally selected by them.

We are party to various other legal proceedings and claims in the ordinary course of our business. We believe that certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on our consolidated financial position, results of operations, or liquidity.

Item 1A. Risk Factors.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. For a discussion of these risks, see "Item 1A. Risk Factors" in our 2014 Form 10-K. The risks described in our 2014 Form 10-K could materially and adversely affect our business, financial condition, cash flows, and results of operations. There have been no material changes to the risks described in our 2014 Form 10-K. We may experience additional risks and uncertainties not currently known to us; or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Issuer Purchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet be Purchased Under the Plan
April 1, 2015 - April 30, 2015	126,086	$ 35.42	—	N/A
May 1, 2015 - May 31, 2015	—	$ —	—	N/A
June 1, 2015 - June 30, 2015	—	$ —	—	N/A

Shares purchased represent shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of restricted stock and restricted stock units held by our employees.

Item 5. Other Information.

Disclosure pursuant to Section 13(r) of the Securities Exchange Act of 1934

Pursuant to Section 13(r) of the Securities Exchange Act of 1934, we, Antero Resources Corporation, may be required to disclose in our annual and quarterly reports to the SEC, whether we or any of our "affiliates" knowingly engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by US economic sanctions. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Because the SEC defines the term "affiliate" broadly, it includes any entity under common "control" with us (and the term "control" is also construed broadly by the SEC).

The description of the activities below has been provided to us by Warburg Pincus LLC ("WP"), affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and/or are members of our board of directors and (ii) beneficially own more than 10% of the equity interests of, and have the right to designate members of the board of directors of Santander Asset Management Investment Holdings Limited ("SAMIH"). SAMIH may therefore be deemed to be under common "control" with us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by SAMIH and its non-U.S. affiliates that may be deemed to be under common "control" with us. The disclosure does not relate to any activities conducted by us or by WP and does not involve our or WP's management. Neither we nor WP has had any involvement in or control over the disclosed activities of SAMIH, and neither we nor WP has independently verified or participated in the preparation of the disclosure. Neither we nor WP is representing as to the accuracy or completeness of the disclosure nor do we or WP undertake any obligation to correct or update it.

We understand that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that "Santander UK holds frozen savings and current accounts for two customers resident in the U.K. who are currently designated by the U.S. for terrorism. The accounts held by each customer were blocked after the customer's designation and have remained blocked and dormant throughout the first half of 2015. No revenue has been generated by Santander UK on these accounts."

"An Iranian national, resident in the U.K., who is currently designated by the U.S. under the Iranian Financial Sanctions Regulations and the Weapons of Mass Destruction Proliferators Sanctions Regulations ("NPWMD sanctions program"), holds a mortgage with Santander UK that was issued prior to any such designation. No further drawdown has been made (or would be allowed) under this mortgage although Santander UK continues to receive repayment installments. In the first half of 2015, total revenue in connection with the mortgage was approximately £1,780 while net profits were negligible relative to the overall profits of Santander UK. Santander UK does not intend to enter into any new relationships with this customer, and any disbursements will only be made in accordance with applicable sanctions. The same Iranian national also holds two investment accounts with Santander Asset Management UK Limited. The accounts have remained frozen during the first half of 2015. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue for the Group in connection with the investment accounts was approximately £120 while net profits in the first quarter of 2015 were negligible relative to the overall profits of Banco Santander, S.A."

Item 6. Exhibits.

The exhibits required to be filed pursuant to the requirements of Item 601 of Regulation S-K are set forth in the Exhibit Index accompanying this Quarterly Report on Form 10-Q and are incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ANTERO RESOURCES CORPORATION

By: /s/ GLEN C. WARREN, JR.
Glen C. Warren, Jr.
President, Chief Financial Officer and Secretary

Date: July 29, 2015

EXHIBIT INDEX

Exhibit Number	Description of Exhibit
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	Amended and Restated Bylaws of Antero Resources Corporation (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
101*	The following financial information from this Quarterly Report on Form 10-Q of Antero Resources Corporation for the quarter ended June 30, 2015 formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Balance Sheets, (ii) Condensed Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Condensed Consolidated Statements of Equity, (iv) Condensed Consolidated Statements of Cash Flows, and (v) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

The exhibits marked with the asterisk symbol (*) are filed or furnished with this Quarterly Report on Form 10-Q.

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Paul M. Rady, Chairman and Chief Executive Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2015 of Antero Resources Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2015

/s/ Paul M. Rady

Paul M. Rady
Chief Executive Officer

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Glen C. Warren, Jr., President and Chief Financial Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2015 of Antero Resources Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2015

/s/ Glen C. Warren, Jr.

Glen C. Warren, Jr.
Chief Financial Officer

Exhibit 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with this Quarterly Report on Form 10-Q of Antero Resources Corporation for the quarter ended June 30, 2015, I, Paul M. Rady, Chief Executive Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: July 29, 2015

/s/ Paul M. Rady

Paul M. Rady
Chief Executive Officer

Exhibit 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with this Quarterly Report on Form 10-Q of Antero Resources Corporation for the quarter ended June 30, 2015, I, Glen C. Warren, Jr., Chief Financial Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: July 29, 2015

/s/ Glen C. Warren, Jr.

Glen C. Warren, Jr.
Chief Financial Officer