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, 2016

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 307,187,980 shares of common stock outstanding as of July 28, 2016.

TABLE OF CONTENTS

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, 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 our Annual Report on Form 10-K for the year ended December 31, 2015 (our “2015 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.

Forward-looking statements may include statements about our:

- ability to successfully complete the pending acquisition of properties from a third party, integrate the assets with our own, and realize the anticipated benefits of the transaction
- 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 meet our minimum volume commitments and 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 2015 Form 10-K on file with 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, 2015 and June 30, 2016
(Unaudited)
(In thousands, except per share amounts)

	December 31, 2015	June 30, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 23,473	28,251
Accounts receivable, net of allowance for doubtful accounts of $1,195 in 2015 and 2016	79,404	71,606
Accrued revenue	128,242	133,479
Derivative instruments	1,009,030	429,920
Other current assets	8,087	6,528
Total current assets	1,248,236	669,784
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	1,996,081	1,984,515
Proved properties	8,211,106	8,794,515
Water handling and treatment systems	565,616	655,251
Gathering systems and facilities	1,502,396	1,596,460
Other property and equipment	46,415	44,919
	12,321,614	13,075,660
Less accumulated depletion, depreciation, and amortization	(1,589,372)	(1,977,790)
Property and equipment, net	10,732,242	11,097,870
Derivative instruments	2,108,450	1,673,907
Other assets	26,565	117,219
Total assets	$ 14,115,493	13,558,780
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 364,160	211,106
Accrued liabilities	194,076	201,320
Revenue distributions payable	129,949	135,054
Derivative instruments	—	2,726
Other current liabilities	19,085	19,226
Total current liabilities	707,270	569,432
Long-term liabilities:		
Long-term debt	4,668,782	4,244,014
Deferred income tax liability	1,370,686	1,063,331
Derivative instruments	—	5,179
Other liabilities	82,077	75,925
Total liabilities	6,828,815	5,957,881
Commitments and contingencies (notes 9 and 13)		
Equity:		
Stockholders' equity:		
Preferred stock, $0.01 par value; authorized - 50,000 shares; none issued	—	—
Common stock, $0.01 par value; authorized - 1,000,000 shares; issued and outstanding 277,036 shares and 304,158 shares, respectively	2,770	3,042
Additional paid-in capital	4,122,811	5,022,848
Accumulated earnings	1,808,811	1,207,512
Total stockholders' equity	5,934,392	6,233,402
Noncontrolling interest in consolidated subsidiary	1,352,286	1,367,497
Total equity	7,286,678	7,600,899

Total liabilities and equity	$ 14,115,493	13,558,780

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Operations and Comprehensive Loss
Three Months Ended June 30, 2015 and 2016
(Unaudited)
(In thousands, except per share amounts)

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2016
Revenue:		
Natural gas sales	$ 242,065	229,787
Natural gas liquids sales	59,525	94,713
Oil sales	23,032	16,740
Gathering, compression, and water handling and treatment	4,490	3,294
Marketing	49,829	90,902
Commodity derivative fair value losses	(2,227)	(684,634)
Total revenue	376,714	(249,198)
Operating expenses:		
Lease operating	6,673	12,043
Gathering, compression, processing, and transportation	166,669	206,060
Production and ad valorem taxes	22,519	17,458
Marketing	79,053	125,977
Exploration	628	1,109
Impairment of unproved properties	26,339	19,944
Depletion, depreciation, and amortization	177,046	197,362
Accretion of asset retirement obligations	408	620
General and administrative (including equity-based compensation expense of $27,582 and $25,816 in 2015 and 2016, respectively)	59,191	60,102
Contract termination and rig stacking	1,937	—
Total operating expenses	540,463	640,675
Operating loss	(163,749)	(889,873)
Other income (expenses):		
Equity in earnings of unconsolidated affiliate	—	484
Interest	(59,823)	(62,595)
Total other expenses	(59,823)	(62,111)
Loss before income taxes	(223,572)	(951,984)
Provision for income tax benefit	84,089	376,494
Net loss and comprehensive loss including noncontrolling interest	(139,483)	(575,490)
Net income and comprehensive income attributable to noncontrolling interest	5,890	20,754
Net loss and comprehensive loss attributable to Antero Resources Corporation	$ (145,373)	(596,244)
Loss per common share	$ (0.52)	(2.12)
Loss per common share—assuming dilution	$ (0.52)	(2.12)
Weighted average number of shares outstanding:		
Basic	277,003	281,786
Diluted	277,003	281,786

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, 2015 and 2016
(Unaudited)
(In thousands, except per share amounts)

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2016
Revenue:		
Natural gas sales	$ 557,007	484,563
Natural gas liquids sales	138,311	167,778
Oil sales	35,489	26,919
Gathering, compression, and water handling and treatment	10,658	7,138
Marketing	107,609	190,118
Commodity derivative fair value gains (losses)	757,327	(404,710)
Total revenue	1,606,401	471,806
Operating expenses:		
Lease operating	14,775	23,336
Gathering, compression, processing, and transportation	330,331	414,798
Production and ad valorem taxes	46,737	36,742
Marketing	152,402	263,910
Exploration	1,999	2,123
Impairment of unproved properties	34,916	35,470
Depletion, depreciation, and amortization	359,346	388,944
Accretion of asset retirement obligations	808	1,218
General and administrative (including equity-based compensation expense of $55,365 and $49,286 in 2015 and 2016, respectively)	118,240	116,389
Contract termination and rig stacking	10,902	—
Total operating expenses	1,070,456	1,282,930
Operating income (loss)	535,945	(811,124)
Other income (expenses):		
Equity in earnings of unconsolidated affiliate	—	484
Interest	(113,008)	(125,879)
Total other expenses	(113,008)	(125,395)
Income (loss) before income taxes	422,937	(936,519)
Provision for income tax (expense) benefit	(163,249)	371,679
Net income (loss) and comprehensive income (loss) including noncontrolling interest	259,688	(564,840)
Net income and comprehensive income attributable to noncontrolling interest	10,630	36,459
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 249,058	(601,299)
Earnings (loss) per common share	$ 0.92	(2.15)
Earnings (loss) per common share—assuming dilution:	$ 0.92	(2.15)
Weighted average number of shares outstanding:		
Basic	271,181	279,418
Diluted	271,192	279,418

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION
Condensed Consolidated Statements of Equity
Six Months Ended June 30, 2016
(Unaudited)
(In thousands)

	Common Stock		Additional paid-in capital	Accumulated earnings	Noncontrolling interest	Total equity
	Shares	Amount				
Balances, December 31, 2015	277,036	$ 2,770	4,122,811	1,808,811	1,352,286	7,286,678
Issuance of common stock in public offering, net of underwriter discounts and offering costs	26,750	268	752,331	—	—	752,599
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	372	4	(4,806)	—	—	(4,802)
Issuance of common units in Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(158)	—	141	(17)
Sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation, net of tax	—	—	107,257	—	6,419	113,676
Equity-based compensation	—	—	45,413	—	3,873	49,286
Net income (loss) and comprehensive income (loss)	—	—	—	(601,299)	36,459	(564,840)
Distributions to noncontrolling interests	—	—	—	—	(31,681)	(31,681)
Balances, June 30, 2016	304,158	$ 3,042	5,022,848	1,207,512	1,367,497	7,600,899

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION
Condensed Consolidated Statements of Cash Flows
Six Months Ended June 30, 2015 and 2016
(Unaudited)
(In thousands)

	Six Months Ended June 30,	
	2015	2016
Cash flows from operating activities:		
Net income (loss) including noncontrolling interest	$ 259,688	(564,840)
Adjustment to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and accretion	360,154	390,162
Impairment of unproved properties	34,916	35,470
Derivative fair value (gains) losses	(757,327)	404,710
Gains on settled derivatives	380,720	616,848
Deferred income tax expense (benefit)	163,249	(371,679)
Equity-based compensation expense	55,365	49,286
Equity in earnings of unconsolidated affiliate	—	(484)
Other	3,999	621
Changes in current assets and liabilities:		
Accounts receivable	(2,987)	7,798
Accrued revenue	66,091	(5,237)
Other current assets	1,047	1,559
Accounts payable	4,579	3,430
Accrued liabilities	15,417	6,431
Revenue distributions payable	8,529	5,105
Other current liabilities	1,668	(474)
Net cash provided by operating activities	595,108	578,706
Cash flows used in investing activities:		
Additions to unproved properties	(131,683)	(58,195)
Drilling and completion costs	(1,009,421)	(709,974)
Additions to water handling and treatment systems	(34,076)	(78,625)
Additions to gathering systems and facilities	(200,045)	(97,300)
Additions to other property and equipment	(2,794)	(1,296)
Investment in unconsolidated affiliate	—	(45,044)
Change in other assets	(759)	(47,925)
Proceeds from asset sales	40,000	—
Net cash used in investing activities	(1,338,778)	(1,038,359)
Cash flows from financing activities:		
Issuance of common stock	537,693	752,599
Proceeds from sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation	—	178,000
Issuance of senior notes	750,000	—
Repayments on bank credit facilities, net	(612,000)	(427,000)
Payments of deferred financing costs	(15,254)	(96)
Distributions to noncontrolling interest in consolidated subsidiary	(12,617)	(31,681)
Employee tax withholding for settlement of equity compensation awards	(4,513)	(4,819)
Other	(2,332)	(2,572)
Net cash provided by financing activities	640,977	464,431
Net increase (decrease) in cash and cash equivalents	(102,693)	4,778
Cash and cash equivalents, beginning of period	245,979	23,473
Cash and cash equivalents, end of period	$ 143,286	28,251
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest	$ 103,133	121,128
Supplemental disclosure of noncash investing activities:		

Decrease in accounts payable and accrued liabilities for additions to property and equipment	$ (210,217)	(155,671)

See accompanying notes to condensed consolidated financial statements.

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

(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 exploration, development, and acquisition of natural gas, 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. Through its consolidated subsidiary, Antero Midstream Partners LP, a publicly-traded limited partnership ("Antero Midstream"), the Company has water handling and treatment operations and gathering and compression operations in the Appalachian Basin. The Company's corporate headquarters are located 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, 2015 consolidated financial statements and notes thereto for a more complete understanding of the Company's operations, financial position, and accounting policies. The December 31, 2015 consolidated financial statements have been filed with the SEC in the Company's 2015 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 December 31, 2015 and June 30, 2016, the results of its operations for the three and six months ended June 30, 2015 and 2016, and its cash flows for the six months ended June 30, 2015 and 2016. 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, 2016 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, fluctuations in the fair value of derivative instruments, 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 except for the exercise of the tag-along option to a leasehold acquisition and the sale of common stock. Both of these items are further described in note 14.

(b) Principles of Consolidation

The accompanying condensed consolidated financial statements include the accounts of Antero Resources Corporation, its wholly-owned subsidiaries, any entities in which the Company owns a controlling interest, and variable interest entities for which the Company is the primary beneficiary. The Company consolidates Antero Midstream as it determined that it is the primary beneficiary based on its significant ownership interest in Antero Midstream, the significance of the Company's activities to Antero Midstream, and its influence over Antero Midstream through the presence of Company executives that serve on the board of directors of Antero Midstream's general partner. All significant intercompany accounts and transactions have been eliminated in the Company's condensed consolidated financial statements. Noncontrolling interest in the Company's condensed consolidated financial statements represents the interests in Antero Midstream which are owned by third-party individuals or entities, or Antero Midstream's general partner. An affiliate of the Company owns the general partner interest in Antero Midstream. Noncontrolling interest is included as a component of equity in the Company's condensed consolidated balance sheets.

Investments in entities for which the Company exercises significant influence, but not control, are accounted for under the equity method. Such investments are included in other assets on the Company's condensed consolidated balance sheets. Income from such investments is included in equity in earnings of unconsolidated affiliate on the Company's condensed consolidated statements of operations and cash flows.

(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, as well as 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 markets for natural gas, NGLs, and oil have experienced significant price fluctuations. Price fluctuations can result from variations in weather, regional levels of production, 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, which may include commodity swap agreements, basis swap agreements, collar agreements, and other similar agreements related to the price risk associated with a portion of the Company's 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 that the counterparty is unable to satisfy its settlement obligations. The fair value of the Company's commodity derivative contracts of approximately $2.1 billion at June 30, 2016 includes the following values by bank counterparty: Morgan Stanley - $568 million; Barclays - $461 million; JP Morgan - $388 million; Wells Fargo - $204 million; Scotiabank - $148 million; Citigroup - $126 million; BNP Paribas - $81 million; Toronto Dominion - $51 million; Canadian Imperial Bank of Commerce - $30 million; Fifth Third - $24 million; Bank of Montreal - $13 million; SunTrust - $6 million; and Capital One - $4 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 condensed 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 ("NOL") 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 and production of natural gas, NGLs, and oil; (2) gathering and compression; (3) water handling and treatment; 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

Marketing revenues and expenses represent activities undertaken by the Company 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) attributable to Antero 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. The Company includes performance share unit awards in the calculation of diluted weighted average shares outstanding based on the number of common shares that would be issuable if June 30, 2016 was the end of the performance period. 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,	
	2015	2016	2015	2016
Basic weighted average number of shares outstanding	277,003	281,786	271,181	279,418
Add: Dilutive effect of non-vested restricted stock units	—	—	11	—
Add: Dilutive effect of outstanding stock options	—	—	—	—
Add: Dilutive effect of performance stock units	—	—		
Diluted weighted average number of shares outstanding	277,003	281,786	271,192	279,418
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings per common share(1):				
Non-vested restricted stock and restricted stock units	2,377	6,982	2,141	6,862
Outstanding stock options	644	706	364	713
Performance stock units	—	724	—	471

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

(l) Adoption of New Accounting Principle

On March 30, 2016, the FASB issued ASU No. 2016-09, *Stock Compensation–Improvements to Employee Share-Based Payment Accounting*. This standard simplifies or clarifies several aspects of the accounting for equity-based payment awards, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Certain of these changes are required to be applied retrospectively, while other changes are required to be applied prospectively. The Company elected to early-adopt the standard as of January 1, 2016.

As permitted by this standard, the Company has elected to account for forfeitures in compensation cost as they occur. This standard also permits an entity to withhold income taxes upon settlement of equity-classified awards at up to the maximum statutory tax rate and requires that such payments be classified as financing activities on the statement of cash flows.

As a result of adopting this standard, cash outflows attributable to tax withholdings on the net settlement of equity-classified awards have been reclassified from operating cash flows to financing cash flows. The retrospective adjustment to the condensed consolidated statement of cash flows for the six months ended June 30, 2015 is as follows (in thousands):

	As Previously Reported Six Months Ended June 30, 2015	Adjustment Effect	As Adjusted Six Months Ended June 30, 2015
Changes in accrued liabilities	$ 10,904	4,513	15,417
Employee tax withholding for settlement of equity compensation awards	—	(4,513)	(4,513)

(3) Antero Midstream Partners LP

In 2014, the Company formed Antero Midstream to own, operate, and develop midstream assets to service Antero's production. Antero Midstream's assets consist of gathering pipelines, compressor stations, and water handling and treatment facilities, through which it provides services to Antero under long-term, fixed-fee contracts. Antero Resources Midstream Management LLC ("Midstream Management"), a wholly-owned subsidiary of Antero Resources Investment LLC ("Antero Investment"), owns the general partnership interest in Antero Midstream, which allows Midstream Management to manage the business and affairs of Antero Midstream. Midstream Management also holds the incentive distribution rights in Antero Midstream. Antero Midstream is an unrestricted subsidiary as defined by Antero's bank credit facility and, as such, Antero Midstream and its subsidiaries are not guarantors of Antero's obligations, and Antero is not a guarantor of Antero Midstream's obligations (see note 12).

On September 23, 2015, Antero contributed (i) all of the outstanding limited liability company interests of Antero Water LLC ("Antero Water") to Antero Midstream and (ii) all of the assets, contracts, rights, permits and properties owned or leased by Antero and used primarily in connection with the construction, ownership, operation, use or maintenance of Antero's advanced waste water treatment complex under construction in Doddridge County, West Virginia, to Antero Treatment LLC ("Antero Treatment"), a subsidiary of Antero Midstream (collectively, (i) and (ii) are referred to herein as the "Contributed Assets").

In consideration for the Contributed Assets, Antero Midstream (i) paid to Antero a cash distribution equal to $552 million, less $171 million of assumed debt, (ii) issued to Antero 10,988,421 common units representing limited partner interests in Antero Midstream, (iii) distributed to Antero proceeds of approximately $241 million from a private placement of Antero Midstream common units, and (iv) has agreed to pay Antero (a) $125 million in cash if Antero Midstream delivers 176,295,000 barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if Antero Midstream delivers 219,200,000 barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. Antero Midstream borrowed $525 million on its bank credit facility in connection with this transaction.

On March 30, 2016, Antero sold 8,000,000 common units representing limited partnership interests in Antero Midstream for $178 million. The sale of the units is reflected in stockholders' equity as additional paid-in capital, net of taxes.

On May 26, 2016, Antero Midstream exercised its option to purchase a 15% equity interest in a regional gathering pipeline, in which Antero is an anchor shipper, for approximately $45 million. This investment is accounted for under the equity method.

Antero owned approximately 66.3% and 61.8% of the limited partner interests of Antero Midstream at December 31, 2015 and June 30, 2016, respectively.

(4) Long-Term Debt

Long-term debt was as follows at December 31, 2015 and June 30, 2016 (in thousands):

	2015	2016
Antero:		
Bank credit facility(a)	$ 707,000	140,000
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	750,000
Net unamortized premium	6,513	5,974
Net unamortized debt issuance costs	(39,731)	(36,960)
Antero Midstream:		
Bank credit facility(b)	620,000	760,000
	$ 4,668,782	4,244,014

(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 assets and are subject to regular semiannual redeterminations. At June 30, 2016, the borrowing base was $4.5 billion and lender commitments were $4.0 billion. The next redetermination of the borrowing base is scheduled to occur in October 2016. The maturity date of the Credit Facility is May 5, 2019.

The Credit Facility is ratably secured by mortgages on substantially all of Antero’s properties and guarantees from Antero’s restricted subsidiaries, as applicable. The Credit Facility contains certain covenants, including restrictions on indebtedness and dividends, and 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, 2015 and June 30, 2016.

As of June 30, 2016, Antero had a total outstanding balance under the Credit Facility of $140 million, with a weighted average interest rate of 2.00%, and outstanding letters of credit of $708 million. As of December 31, 2015, Antero had an outstanding balance under the Credit Facility of $707 million, with a weighted average interest rate of 2.32%, and outstanding letters of credit of $702 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from 0.375% to 0.50% of the unused portion 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, 2016, lender commitments were $1.5 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, 2015 and June 30, 2016.

As of June 30, 2016, Antero Midstream had an outstanding balance under the Midstream Facility of $760 million with a weighted average interest rate of 1.96%. As of December 31, 2015, Antero Midstream had a total outstanding balance under the Midstream Facility of $620 million with a weighted average interest rate of 1.92%. 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 portion 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 to the extent of the value of the collateral securing the Credit Facility. 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 at redemption prices ranging from 104.50% currently to 100.00% on or after December 1, 2018. 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 to the extent of the value of the collateral securing the Credit Facility. 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 to the extent of the value of the collateral securing the Credit Facility. 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, 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 to the extent of the value of the collateral securing the Credit Facility. 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, 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, 2017. At December 31, 2015 and June 30, 2016, there were no outstanding borrowings under this facility.

(5) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the six months ended June 30, 2016 (in thousands).

Asset retirement obligations—December 31, 2015	$	30,612
Obligations incurred for wells drilled		2,665
Accretion expense		1,218
Asset retirement obligations—June 30, 2016	$	34,495

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

(6) 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 7,769,049 shares were available for future grant under the Plan as of June 30, 2016.

In connection with the Antero Midstream initial public offering ("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 7,707,464 common units were available for future grant under the Midstream Plan as of June 30, 2016.

The Company's equity-based compensation expense was as follows for the three and six months ended June 30, 2015 and 2016 (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2015	2016	2015	2016
Profits interests awards	$12,363	—	$27,081	—
Restricted stock unit awards	10,235	18,146	18,671	35,613
Stock options	642	641	771	1,301
Performance share unit awards	—	2,466	—	3,349
Antero Midstream phantom and restricted unit awards	4,267	4,013	8,692	8,001
Equity awards issued to directors	75	550	150	1,022
Total expense	$27,582	25,816	$55,365	49,286

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 provided 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 provided a mechanism that determines how the shares of the Company's common stock held by Antero Investment would be allocated among its members, 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 recognized approximately $486 million of equity-based compensation expense for the vested profits interests from the fourth quarter of 2013 through the fourth quarter of 2015. The profits interest awards were fully vested as of December 31, 2015. Because consideration for the profits interest awards was deemed given by Antero Investment, the charge to equity-based compensation expense was 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 Company's IPO, and no additional profits interest awards have been made since the Company's IPO.

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. Forfeitures are accounted for as they occur through reversal of expense on awards that were forfeited during the period. 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 for the six months ended June 30, 2016 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2015	6,529,459	$ 33.48	$ 142,342
Granted	1,217,474	$ 27.06	
Vested	(527,795)	$ 55.48	
Forfeited	(217,935)	$ 27.68	
Total awarded and unvested—June 30, 2016	7,001,203	$ 30.88	$ 181,891

Intrinsic values are based on the closing price of the Company's stock on the referenced dates. Unamortized expense of $168.9 million at June 30, 2016 is expected to be recognized over a weighted average period of approximately 2.4 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. Forfeitures are accounted for as they occur through reversal of expense on awards that were forfeited during the period. 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, 2016 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2015	720,887	$ 50.44	9.14	$ —
Granted	—	$ —		
Exercised	—	—		
Forfeited	(21,250)	$ 50.00		
Expired	—	—		
Outstanding at June 30, 2016	699,637	$ 50.45	8.55	$ —
Vested or expected to vest as of June 30, 2016	699,637	$ 50.45	8.55	$ —
Exercisable at June 30, 2016	210,715	$ 50.92	8.20	$ —

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

As of June 30, 2016, there was $6.7 million of unamortized equity-based compensation expense related to nonvested stock options. That expense is expected to be recognized over a weighted average period of approximately 2.7 years.

Performance Share Unit Awards

Performance Share Unit Awards Based on Price Targets

In the first quarter of 2016, the Company granted performance share unit awards ("PSUs") to certain of its executive officers. PSUs vest conditioned on the closing price of the Company's common stock achieving specific thresholds over 10-day periods, subject to the following vesting restrictions: no PSUs may vest before the first anniversary of the grant date; no more than one-third of the PSUs may vest before the second anniversary of the grant date; and no more than two-thirds of the PSUs may vest before the third anniversary of the grant date. Any PSUs which have not vested by the fifth anniversary of the grant date will expire. Expense related to these PSUs is recognized on a graded basis over three years.

Performance Share Unit Awards Based on Total Shareholder Return

In the second quarter of 2016, the Company granted PSUs to certain of its employees and executive officers which vest based on the total shareholder return ("TSR") of the Company's common stock relative to the TSR of a peer group of companies over a three-year performance period. The number of performance shares which may ultimately be earned ranges from zero to 200% of the PSUs granted.

Summary Information for Performance Share Unit Awards

A summary of PSU activity for the six months ended June 30, 2016 is as follows:

	Number of units	Weighted average grant date fair value
Total awarded and unvested—December 31, 2015	—	$ —
Granted	790,890	$ 29.77
Vested	—	$ —
Forfeited	(5,589)	$ 32.97
Total awarded and unvested—June 30, 2016	785,301	$ 29.75

The grant-date fair values of PSUs were determined using a Monte Carlo simulation, which uses a probabilistic approach for estimating the fair values of the awards. Expected volatilities were 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 yield available for zero-coupon U.S. government issues with remaining terms corresponding to the service periods of the PSUs. A dividend yield of zero was assumed.

The following table presents information regarding the weighted average fair value for PSUs granted during the six months ended June 30, 2016 and the assumptions used to determine the fair values.

	Six months ended June 30, 2016
Dividend yield	— %
Volatility	45 %
Risk-free interest rate	1.01 %
Weighted average fair value of awards granted	$ 29.77

As of June 30, 2016, there was $20.0 million of unamortized equity-based compensation expense related to unvested PSUs. That expense is expected to be recognized over a weighted average period of approximately 2.4 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. Forfeitures are accounted for as they occur through reversal of expense on awards that were forfeited during the period. 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 for the six months ended June 30, 2016 is as follows:

	Number of units	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2015	1,667,832	$ 28.97	$ 38,060
Granted	290,254	$ 21.24	
Vested	(6,354)	$ 24.98	
Forfeited	(62,728)	$ 28.42	
Total awarded and unvested—June 30, 2016	1,889,004	$ 27.81	$ 52,647

Intrinsic values are based on the closing price of Antero Midstream's common units on the referenced dates. Unamortized expense of $42.5 million at June 30, 2016 is expected to be recognized over a weighted average period of approximately 2.6 years.

(7) Financial Instruments

The carrying values of accounts receivable and accounts payable at December 31, 2015 and June 30, 2016 approximated market value because of their short-term nature. The carrying values of the amounts outstanding under the Credit Facility and Midstream Facility at December 31, 2015 and June 30, 2016 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 $2.6 billion at December 31, 2015 and $3.3 billion at June 30, 2016.

See note 8 for information regarding the fair value of derivative financial instruments.

(8) 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 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.

During the six months ended June 30, 2015 and 2016, the Company was party to various natural gas and NGLs fixed price swap contracts. The Company enters into these swap contracts when management believes that favorable future sales prices for the Company's production can be secured. Under these swap agreements, when actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the difference to the counterparty. When actual commodity prices are below the contractually provided fixed price, the Company receives the difference from the counterparty.

In addition to fixed price swap contracts, 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 at which the Company sells a portion of its natural gas production. 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, 2016, the Company's fixed price natural gas and NGLs swap contracts under short positions from July 1, 2016 through December 31, 2022 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; Mont Belvieu-TET=Mont Belvieu Propane):

	Natural gas MMbtu/day	Propane Bbls/day	Weighted average index price
Three months ending September 30, 2016:			
TCO ($/MMBtu)	60,000	—	$ 4.81
Dominion South ($/MMBtu)	272,500	—	$ 5.24
NYMEX ($/MMBtu)	1,110,000	—	$ 3.44
CGTLA ($/MMBtu)	170,000	—	$ 4.03
Mont Belvieu-TET ($/Gallon)	—	30,000	$ 0.58
Total	1,612,500	30,000	
Three months ending December 31, 2016:			
TCO ($/MMBtu)	60,000	—	$ 5.01
Dominion South ($/MMBtu)	272,500	—	$ 5.47
NYMEX ($/MMBtu)	1,110,000	—	$ 3.57
CGTLA ($/MMBtu)	170,000	—	$ 4.20
Mont Belvieu-TET ($/Gallon)	—	30,000	$ 0.61
Total	1,612,500	30,000	
Year ending December 31, 2017:			
NYMEX ($/MMBtu)	1,370,000	—	$ 3.39
CGTLA ($/MMBtu)	420,000	—	$ 4.27
CCG ($/MMBtu)	70,000	—	$ 4.57
Mont Belvieu-TET ($/Gallon)	—	31,500	$ 0.42
Total	1,860,000	31,500	
Year ending December 31, 2018:			
NYMEX ($/MMBtu)	2,002,500	—	$ 3.91
Mont Belvieu-TET ($/Gallon)	—	2,000	$ 0.65
Total	2,002,500	2,000	
Year ending December 31, 2019:			
NYMEX ($/MMBtu)	2,330,000		$ 3.70
Year ending December 31, 2020:			
NYMEX ($/MMBtu)	1,377,500		$ 3.66
Year ending December 31, 2021:			
NYMEX ($/MMBtu)	630,000		$ 3.36
Year ending December 31, 2022:			
NYMEX ($/MMBtu)	120,000		$ 3.24

As of June 30, 2016, 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, were as follows:

	Natural gas MMbtu/day	Hedged Differential
Six months ending December 31, 2016:	290,000	$ (0.45)
Year ending December 31, 2017:	125,000	$ (0.49)

As of June 30, 2016, 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, were as follows:

	Natural gas MMbtu/day	Hedged Differential
Six months ending December 31, 2016:	170,000	$ 0.34
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, 2015 and June 30, 2016. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	December 31, 2015		June 30, 2016	
	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	$ 1,009,030	Current assets	$ 429,920
Commodity contracts	Long-term assets	2,108,450	Long-term assets	1,673,907
Total asset derivatives		3,117,480		2,103,827
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	—	Current liabilities	2,726
Commodity contracts	Long-term liabilities	—	Long-term liabilities	5,179
Total liability derivatives		—		7,905
Net derivatives		$ 3,117,480		$ 2,095,922

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, 2015			June 30, 2016		
	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	$3,163,639	(46,159)	3,117,480	$2,303,100	(199,273)	2,103,827
Commodity derivative liabilities	$ —	—	—	$ (8,308)	403	(7,905)

The following is a summary of derivative fair value gains and where such values are recorded in the condensed consolidated statements of operations for three and six months ended June 30, 2015 and 2016 (in thousands):

	Statement of operations location	Three months ended June 30, 2015	Three months ended June 30, 2016	Six months ended June 30, 2015	Six months ended June 30, 2016
Commodity derivative fair value gains (losses)	Revenue	$ (2,227)	(684,634)	$ 757,327	(404,710)

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

(9) Contingencies

The Company is the plaintiff in two nearly identical lawsuits against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively "SJGC") pending in United States District Court in Colorado. The Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC has short paid, and continues to short pay, the Company in connection with two long term gas contracts. Under those contracts, SJGC are long term purchasers of some of the Company's natural gas production. Deliveries under the contracts began in October 2011 and the delivery obligation continues through October 2019. SJGC unilaterally breached the contracts claiming 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. Beginning in October 2014, SJGC began short paying the Company based on indexes unilaterally selected by SJGC and not the index specified in the contract. The Company contends that no market disruption event has occurred and that SJGC have breached the contracts by failing to pay the Company based on the express price terms of the contracts. Through June 30, 2016, the Company estimates that it is owed approximately $46 million more than SJGC has paid using the indexes unilaterally selected by them.

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively "WGL") are also involved in a pricing dispute involving contracts that the Company began delivering gas under in January 2016. The Company has invoiced WGL at the index price specified in the contract and WGL has paid the Company based on that invoice price; however, WGL maintains that the index price is no longer appropriate under the contracts and that an undefined alternative index is more appropriate for the delivery point of the gas. We expect that the matter will be submitted to arbitration. The Company believes that there is no basis for WGL's position and intends to vigorously dispute the WGL claim in arbitration and the courts.

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 cash flows.

(10) 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. There were no such costs incurred during the three and six months ended June 30, 2016.

(11) Segment Information

See note 2(i) for a description of the Company's determination of its reportable segments. Revenues from gathering and compression and water handling and treatment operations are primarily derived from intersegment transactions for services provided to the Company's exploration and production operations. 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.

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

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 water handling and treatment segments based on the nature of the expenses and on a combination of the segments' proportionate share of the Company's consolidated property and equipment, capital expenditures, and labor costs, as applicable. 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 six months ended June 30, 2015 and 2016 (in thousands):

	Exploration and production	Gathering and compression	Water handling	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

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

	Exploration and production	Gathering and compression	Water handling	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2016:						
Sales and revenues:						
Third-party	$ (343,394)	3,131	163	90,902	—	(249,198)
Intersegment	3,899	68,785	64,730	—	(137,414)	—
Total	$ (339,495)	71,916	64,893	90,902	(137,414)	(249,198)
Operating expenses:						
Lease operating	$ 12,257	—	34,317	—	(34,531)	12,043
Gathering, compression, processing, and transportation	267,738	6,997	—	—	(68,675)	206,060
Depletion, depreciation, and amortization	173,015	17,172	7,175	—	—	197,362
General and administrative expense	47,167	10,138	3,168	—	(371)	60,102
Other operating expenses	37,848	450	4,294	125,977	(3,461)	165,108
Total	538,025	34,757	48,954	125,977	(107,038)	640,675
Operating income (loss)	$ (877,520)	37,159	15,939	(35,075)	(30,376)	(889,873)
Segment assets	$ 11,919,732	1,598,826	569,624	23,045	(552,447)	13,558,780
Capital expenditures for segment assets	$ 375,247	48,614	41,589	—	(30,183)	435,267

The operating results and assets of the Company's reportable segments were as follows for the six months ended June 30, 2015 and 2016 (in thousands):

	Exploration and production	Gathering and compression	Water handling and treatment	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

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

	Exploration and production	Gathering and compression	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2016:						
Sales and revenues:						
Third-party	$ 274,550	6,718	420	190,118	—	471,806
Intersegment	7,724	134,825	130,919	—	(273,468)	—
Total	$ 282,274	141,543	131,339	190,118	(273,468)	471,806
Operating expenses:						
Lease operating	$ 23,589	—	75,031	—	(75,284)	23,336
Gathering, compression, processing, and transportation	535,183	14,167	—	—	(134,552)	414,798
Depletion, depreciation, and amortization	340,567	34,240	14,137	—	—	388,944
General and administrative expense	90,719	19,473	6,924	—	(727)	116,389
Other operating expenses	73,013	899	8,498	263,910	(6,857)	339,463
Total	1,063,071	68,779	104,590	263,910	(217,420)	1,282,930
Operating income (loss)	$ (780,797)	72,764	26,749	(73,792)	(56,048)	(811,124)
Segment assets	$11,919,732	1,598,826	569,624	23,045	(552,447)	13,558,780
Capital expenditures for segment assets	$ 825,077	97,300	78,625	—	(55,612)	945,390

(12) Subsidiary Guarantors

Antero's wholly-owned subsidiaries each have fully and unconditionally guaranteed Antero's senior notes. Antero Midstream and its subsidiaries 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 4). 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, 2015 and June 30, 2016, and the related Condensed Consolidating Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2015 and 2016 and Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2015 and 2016 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 are not restricted from making distributions to the Parent.

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

Condensed Consolidating Balance Sheets
December 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 16,590	—	6,883	—	23,473
Accounts receivable, net	76,697	—	2,707	—	79,404
Intercompany receivables	2,138	—	65,712	(67,850)	—
Accrued revenue	128,242	—	—	—	128,242
Derivative instruments	1,009,030	—	—	—	1,009,030
Other current assets	8,087	—	—	—	8,087
Total current assets	1,240,784	—	75,302	(67,850)	1,248,236
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	1,996,081	—	—	—	1,996,081
Proved properties	8,243,901	—	—	(32,795)	8,211,106
Water handling and treatment systems	—	—	565,616	—	565,616
Gathering systems and facilities	16,561	—	1,485,835	—	1,502,396
Other property and equipment	46,415	—	—	—	46,415
	10,302,958	—	2,051,451	(32,795)	12,321,614
Less accumulated depletion, depreciation, and amortization	(1,431,747)	—	(157,625)	—	(1,589,372)
Property and equipment, net	8,871,211	—	1,893,826	(32,795)	10,732,242
Derivative instruments	2,108,450	—	—	—	2,108,450
Investments in subsidiaries	(302,336)	—	—	302,336	—
Contingent acquisition consideration	178,049	—	—	(178,049)	—
Other assets, net	15,661	—	10,904	—	26,565
Total assets	$ 12,111,819	—	1,980,032	23,642	14,115,493
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 303,197	—	60,963	—	364,160
Intercompany payable	65,712	—	2,138	(67,850)	—
Accrued liabilities	158,713	—	35,363	—	194,076
Revenue distributions payable	129,949	—	—	—	129,949
Other current liabilities	18,935	—	150	—	19,085
Total current liabilities	676,506	—	98,614	(67,850)	707,270
Long-term liabilities:					
Long-term debt	4,048,782	—	620,000	—	4,668,782
Deferred income tax liability	1,370,686	—	—	—	1,370,686
Contingent acquisition consideration	—	—	178,049	(178,049)	—
Other liabilities	81,453	—	624	—	82,077
Total liabilities	6,177,427	—	897,287	(245,899)	6,828,815
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,082,745	(1,082,745)	—
Common stock	2,770	—	—	—	2,770
Additional paid-in capital	4,122,811	—	—	—	4,122,811
Accumulated earnings	1,808,811	—	—	—	1,808,811

Total stockholders' equity	5,934,392	—	1,082,745	(1,082,745)	5,934,392
Noncontrolling interest in consolidated subsidiary	—	—	—	1,352,286	1,352,286
Total equity	5,934,392	—	1,082,745	269,541	7,286,678
Total liabilities and equity	$ 12,111,819	—	1,980,032	23,642	14,115,493

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

Condensed Consolidating Balance Sheet
June 30, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 19,567	—	8,684	—	28,251
Accounts receivable, net	70,347	—	1,259	—	71,606
Intercompany receivables	2,142	—	54,794	(56,936)	—
Accrued revenue	133,479	—	—	—	133,479
Derivative instruments	429,920	—	—	—	429,920
Other current assets	6,422	—	106	—	6,528
Total current assets	661,877	—	64,843	(56,936)	669,784
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	1,984,515	—	—	—	1,984,515
Proved properties	8,882,922	—	—	(88,407)	8,794,515
Water handling and treatment systems	—	—	655,251	—	655,251
Gathering systems and facilities	16,892	—	1,579,568	—	1,596,460
Other property and equipment	44,919	—	—	—	44,919
	10,929,248	—	2,234,819	(88,407)	13,075,660
Less accumulated depletion, depreciation, and amortization	(1,772,202)	—	(205,588)	—	(1,977,790)
Property and equipment, net	9,157,046	—	2,029,231	(88,407)	11,097,870
Derivative instruments	1,673,907	—	—	—	1,673,907
Investments in subsidiaries	(350,558)	—	—	350,558	—
Contingent acquisition consideration	184,906	—	—	(184,906)	—
Other assets, net	58,423	—	58,796	—	117,219
Total assets	$ 11,385,601	—	2,152,870	20,309	13,558,780
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 124,939	—	86,167	—	211,106
Intercompany payable	54,794	—	2,142	(56,936)	—
Accrued liabilities	187,712	—	13,608	—	201,320
Revenue distributions payable	135,054	—	—	—	135,054
Derivative instruments	2,726	—	—	—	2,726
Other current liabilities	19,068	—	158	—	19,226
Total current liabilities	524,293	—	102,075	(56,936)	569,432
Long-term liabilities:					
Long-term debt	3,484,014	—	760,000	—	4,244,014
Deferred income tax liability	1,063,331	—	—	—	1,063,331
Contingent acquisition consideration	—	—	184,906	(184,906)	—
Derivative instruments	5,179	—	—	—	5,179
Other liabilities	75,382	—	543	—	75,925
Total liabilities	5,152,199	—	1,047,524	(241,842)	5,957,881
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,105,346	(1,105,346)	—
Common stock	3,042	—	—	—	3,042
Additional paid-in capital	5,022,848	—	—	—	5,022,848
Accumulated earnings	1,207,512	—	—	—	1,207,512

Total stockholders' equity	6,233,402	—	1,105,346	(1,105,346)	6,233,402
Noncontrolling interest in consolidated subsidiary	—	—	—	1,367,497	1,367,497
Total equity	6,233,402	—	1,105,346	262,151	7,600,899
Total liabilities and equity	$ 11,385,601	—	2,152,870	20,309	13,558,780

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)
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 handling and treatment	1,826	—	56,593	(53,929)	4,490
Marketing	49,829	—	—	—	49,829
Commodity derivative fair value losses	(2,227)	—	—	—	(2,227)
Other 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 (loss)	(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, 2015 and June 30, 2016

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)
Three Months Ended June 30, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:					
Natural gas sales	$ 229,787	—	—	—	229,787
Natural gas liquids sales	94,713	—	—	—	94,713
Oil sales	16,740	—	—	—	16,740
Gathering, compression, and water handling and treatment	—	—	136,809	(133,515)	3,294
Marketing	90,902	—	—	—	90,902
Commodity derivative fair value losses	(684,634)	—	—	—	(684,634)
Other income	3,899	—	—	(3,899)	—
Total revenue	(248,593)	—	136,809	(137,414)	(249,198)
Operating expenses:					
Lease operating	12,257	—	34,317	(34,531)	12,043
Gathering, compression, processing, and transportation	267,738	—	6,997	(68,675)	206,060
Production and ad valorem taxes	16,175	—	1,283	—	17,458
Marketing	125,977	—	—	—	125,977
Exploration	1,109	—	—	—	1,109
Impairment of unproved properties	19,944	—	—	—	19,944
Depletion, depreciation, and amortization	173,222	—	24,140	—	197,362
Accretion of asset retirement obligations	620	—	—	—	620
General and administrative	47,167	—	13,306	(371)	60,102
Accretion of contingent acquisition consideration	—	—	3,461	(3,461)	—
Total operating expenses	664,209	—	83,504	(107,038)	640,675
Operating income (expense)	(912,802)	—	53,305	(30,376)	(889,873)
Other income (expenses):					
Equity in earnings of unconsolidated affiliate	—	—	484	—	484
Interest	(58,910)	—	(3,878)	193	(62,595)
Equity in net income (loss) of subsidiaries	(1,026)	—	—	1,026	—
Total other expenses	(59,936)	—	(3,394)	1,219	(62,111)
Income (loss) before income taxes	(972,738)	—	49,911	(29,157)	(951,984)
Provision for income tax benefit	376,494	—	—	—	376,494
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(596,244)	—	49,911	(29,157)	(575,490)
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	20,754	20,754
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (596,244)	—	49,911	(49,911)	(596,244)

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

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 handling and treatment	5,693	—	108,836	(103,871)	10,658
Marketing	107,609	—	—	—	107,609
Commodity derivative fair value gains	757,327	—	—	—	757,327
Other 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, 2015 and June 30, 2016

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)
Six Months Ended June 30, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:					
Natural gas sales	$ 484,563	—	—	—	484,563
Natural gas liquids sales	167,778	—	—	—	167,778
Oil sales	26,919	—	—	—	26,919
Gathering, compression, and water handling and treatment	—	—	272,882	(265,744)	7,138
Marketing	190,118	—	—	—	190,118
Commodity derivative fair value gains	(404,710)	—	—	—	(404,710)
Other income	7,724	—	—	(7,724)	—
Total revenue	472,392	—	272,882	(273,468)	471,806
Operating expenses:					
Lease operating	23,589	—	75,031	(75,284)	23,336
Gathering, compression, processing, and transportation	535,183	—	14,167	(134,552)	414,798
Production and ad valorem taxes	34,202	—	2,540	—	36,742
Marketing	263,910	—	—	—	263,910
Exploration	2,123	—	—	—	2,123
Impairment of unproved properties	35,470	—	—	—	35,470
Depletion, depreciation, and amortization	340,981	—	47,963	—	388,944
Accretion of asset retirement obligations	1,218	—	—	—	1,218
General and administrative	90,719	—	26,397	(727)	116,389
Accretion of contingent acquisition consideration	—	—	6,857	(6,857)	—
Total operating expenses	1,327,395	—	172,955	(217,420)	1,282,930
Operating income	(855,003)	—	99,927	(56,048)	(811,124)
Other income (expenses):					
Equity in earnings of unconsolidated affiliate	—	—	484	—	484
Interest	(118,733)	—	(7,582)	436	(125,879)
Equity in net income of subsidiaries	758	—	—	(758)	—
Total other expenses	(117,975)	—	(7,098)	(322)	(125,395)
Income before income taxes	(972,978)	—	92,829	(56,370)	(936,519)
Provision for income tax expense	371,679	—	—	—	371,679
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(601,299)	—	92,829	(56,370)	(564,840)
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	36,459	36,459
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (601,299)	—	92,829	(92,829)	(601,299)

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

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	$ 510,830	—	84,278	—	595,108
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 water handling and treatment 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)
Net 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)
Employee tax withholding for settlement of equity compensation awards	(4,513)	—	—	—	(4,513)
Other	(2,332)	—	—	—	(2,332)
Net cash provided by (used in) financing activities	615,613	—	(41,679)	67,043	640,977
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

ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2015 and June 30, 2016

Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 465,719	—	168,599	(55,612)	578,706
Cash flows used in investing activities:					
Additions to unproved properties	(58,195)	—	—	—	(58,195)
Drilling and completion costs	(765,586)	—	—	55,612	(709,974)
Additions to water handling and treatment systems	—	—	(78,625)	—	(78,625)
Additions to gathering systems and facilities	(331)	—	(96,969)	—	(97,300)
Additions to other property and equipment	(1,296)	—	—	—	(1,296)
Investments in unconsolidated affiliates	—	—	(45,044)	—	(45,044)
Change in other assets	(44,835)	—	(3,090)	—	(47,925)
Net distributions from subsidiaries	51,296	—	—	(51,296)	—
Net cash used in investing activities	(818,947)	—	(223,728)	4,316	(1,038,359)
Cash flows provided by financing activities:					
Issuance of common stock	752,599	—	—	—	752,599
Sale of common units in Antero Midstream Partners LP by Antero Resources Corporation	178,000	—	—	—	178,000
Borrowings (repayments) on bank credit facility, net	(567,000)	—	140,000	—	(427,000)
Payments of deferred financing costs	(96)	—	—	—	(96)
Distributions	—	—	(82,977)	51,296	(31,681)
Employee tax withholding for settlement of equity compensation awards	(4,802)	—	(17)	—	(4,819)
Other	(2,496)	—	(76)	—	(2,572)
Net cash provided by financing activities	356,205	—	56,930	51,296	464,431
Net increase in cash and cash equivalents	2,977	—	1,801	—	4,778
Cash and cash equivalents, beginning of period	16,590	—	6,883	—	23,473
Cash and cash equivalents, end of period	$ 19,567	—	8,684	—	28,251

(13) Commitments

The following is a schedule of future minimum payments for firm transportation, drilling rig and completion services, processing, gathering and compression, and office and equipment agreements, as well as leases that have remaining lease terms in excess of one year as of June 30, 2016 (in millions).

	Firm transportation (a)	Processing, gathering and compression (b)	Drilling rigs and completion services (c)	Office and equipment (d)	Total
Year ending June 30:					
2017	$ 508	343	106	13	970
2018	840	320	98	12	1,270
2019	1,014	211	86	10	1,321
2020	1,073	186	17	8	1,284
2021	1,076	185	—	7	1,268
Thereafter	10,469	783	—	28	11,280
Total	$ 14,980	2,028	307	78	17,393

(a) Firm Transportation

The Company has entered into firm transportation agreements with various pipelines in order to facilitate the delivery of its production to market. These contracts commit the Company 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 are based on the

Company's minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(b) Processing, Gathering, and Compression Service Commitments

The Company has entered into various long-term gas processing agreements for certain of its production that will allow it to realize the value of its NGLs. The minimum payment obligations under the agreements are presented in the table.

The Company has various gathering and compression service agreements with third parties that provide for payments based on volumes gathered or compressed. The minimum payment obligations under these agreements are presented in the table.

The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest. The table does not include intracompany commitments.

(c) Drilling Rig Service Commitments

The Company has obligations under agreements with service providers to procure drilling rigs and completion services. The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(d) Office and Equipment Leases

The Company leases various office space and equipment, as well as field equipment, under capital and operating lease arrangements.

(14) Leasehold Acquisition and Related Issuance of Common Stock

On June 9, 2016, we entered into an agreement to acquire approximately 55,000 net acres of Marcellus Shale leasehold located primarily in Wetzel, Tyler, and Doddridge Counties in West Virginia, including approximately 14 MMcfe per day of net production, for a purchase price of approximately $450 million. The transaction is expected to close in the third quarter of 2016.

Additionally, in July 2016, a third party exercised its 30-day option to sell the remaining working interest in the acquired properties, or an additional 11,500 net acres, to us on similar terms. The exercise of this option will increase the total purchase price for the acquisition by approximately $95 million, resulting in a total purchase price for the acquisition of approximately $545 million.

To finance the acquisition, on June 15, 2016 we issued 26,750,000 shares of our common stock and realized proceeds from the sale of approximately $753 million, net of offering expenses. We also granted the underwriters a 30-day option to purchase an additional 4,012,500 common shares. In July 2016, the underwriters partially exercised the option and purchased an additional 3,012,500 shares, resulting in additional net proceeds from the offering of approximately $85 million. In addition to funding this acquisition, the offering proceeds will be used for general corporate purposes, including funding future development of the properties.

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, our ability to close 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. For more information, please refer to the Annual Report on Form 10-K for the year ended December 31, 2015, filed with the SEC on February 24, 2016.

In this section, references to "Antero," "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 exploration, 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, 2016, we held approximately 574,000 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 operate in the following industry segments: (i) the exploration and production of natural gas, NGLs, and oil; (ii) gathering and compression; (iii) water handling and treatment; and (iv) marketing. 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 free of charge our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. 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.

2016 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. These events continued throughout 2015 and into 2016 and, along with slower economic growth in China, have led to the continuation of low commodity prices. Spot prices for WTI declined from approximately $106.00 per Bbl in June 2014 to less than $50.00 per Bbl in January 2015, and have remained at or below $50.00 per Bbl since mid-2015. Spot prices for Henry Hub natural gas declined from approximately $4.40 per MMBtu in January 2014 to $3.00 per MMBtu in January 2015. Prices further declined to less than $2.00 per MMBtu in March 2016, although they have recently recovered to approximately $2.80 per MMBtu in June 2016. Spot prices for propane, which is the largest portion of our NGLs sales, declined from approximately $1.55 per gallon in January 2014 to less than $0.50 per gallon in January 2015, and declined further to less than $0.35 per gallon in January 2016, although prices recovered to approximately $0.50 per gallon in June 2016.

In response to these market conditions and concerns about access to capital markets, many U.S. exploration and production companies significantly reduced their capital spending plans in 2015, and further reduced their capital spending plans for 2016. Our capital budget for drilling, completions, and land in 2016 is $1.4 billion, a 24% reduction from our 2015 capital expenditures. We plan to operate an average of 7 drilling rigs in 2016 as compared to an average of 14 rigs in 2015, and we plan to complete 110 horizontal wells in the Marcellus and Utica Shales in 2016 as compared to 131 in 2015. In conjunction with the reduction in our capital expenditures during 2016, we plan to defer the completion of 70 wells until 2017.

We believe that our 2016 capital budget will be fully funded through operating cash flows, available borrowing capacity under our revolving credit facility, and potential capital market transactions. We will continue to monitor commodity prices and may revise the capital budget if conditions warrant. Additionally, given the current commodity price environment, we have evaluated the carrying value of our proved properties. See "—Critical Accounting Policies and Estimates" for a discussion of such evaluation.

Production and Financial Results

For the three months ended June 30, 2016, we generated cash flow from operations of $239 million, a net loss of $596 million, and Adjusted EBITDAX of $332 million. This compares to cash flow from operations of $244 million, a net loss of $145 million, and Adjusted EBITDAX of $268 million for the three months ended June 30, 2015. The net loss of $596 million for the three months ended June 30, 2016 included (i) $685 million of commodity derivative fair value losses, net of $293 million of settled derivative gains, (ii) a noncash charge of $26 million for equity-based compensation, (iii) a noncash charge of $20 million for impairments of unproved properties, and (iv) a noncash deferred tax benefit of $376 million. See "—Non-GAAP Financial Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income.

For the three months ended June 30, 2016, our production totaled approximately 160 Bcfe, or 1,762 MMcfe per day, a 19% increase compared to 135 Bcfe, or 1,484 MMcfe per day, for the three months ended June 30, 2015. The average price received for production for the three months ended June 30, 2016 was $2.13 per Mcfe before the effects of gains on settled derivatives compared to $2.40 per Mcfe for the three months ended June 30, 2015. Average prices including the effects of gains on settled derivatives were $3.95 per Mcfe for the three months ended June 30, 2016 compared to $3.85 per Mcfe for the three months ended June 30, 2015.

For the six months ended June 30, 2016, we generated cash flow from operations of $579 million, a net loss of $601 million, and Adjusted EBITDAX of $688 million. This compares to cash flow from operations of $595 million, net income of $249 million, and Adjusted EBITDAX of $623 million for the six months ended June 30, 2015. The net loss of $601 million for the six months ended June 30, 2016 included (i) $405 million of commodity derivative fair value losses, net of $617 million of settled derivative gains, (ii) a noncash charge of $49 million for equity-based compensation, (iii) a noncash charge of $35 million for impairments of unproved properties, and (iv) a noncash deferred tax benefit of $372 million. See "—Non-GAAP Financial Measure" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income.

For the six months ended June 30, 2016, our production totaled approximately 320 Bcfe, or 1,760 MMcfe per day, a 19% increase compared to 269 Bcfe, or 1,485 MMcfe per day, for the six months ended June 30, 2015. The average price received for production for the six months ended June 30, 2016 was $2.12 per Mcfe before the effects of gains on settled derivatives compared to $2.72 per Mcfe for the six months ended June 30, 2015. Average prices including the effects of gains on settled derivatives were $4.05 per Mcfe for the six months ended June 30, 2016 compared to $4.14 per Mcfe for the six months ended June 30, 2015.

Leasehold Acquisition and Related Issuance of Common Stock

On June 9, 2016, we entered into an agreement to acquire approximately 55,000 net acres of Marcellus Shale leasehold located primarily in Wetzel, Tyler, and Doddridge Counties in West Virginia, including approximately 14 MMcfe per day of net production, for a purchase price of approximately $450 million. The transaction is expected to close in the third quarter of 2016.

Additionally, in July 2016, a third party exercised its 30-day option to sell the remaining working interest in the acquired properties, or an additional 11,500 net acres, to us on similar terms. The exercise of this option will increase the total purchase price of the acquisition by approximately $95 million, resulting in a total purchase price for the acquisition of approximately $545 million.

To finance the acquisition, on June 15, 2016 we issued 26,750,000 shares of our common stock and realized proceeds from the sale of approximately $753 million, net of offering expenses. We also granted the underwriters a 30-day option to purchase an additional 4,012,500 common shares. In July 2016, the underwriters partially exercised the option and purchased an additional 3,012,500 shares, resulting in additional net proceeds from the offering of approximately $85 million. In addition to funding this acquisition, the offering proceeds will be used for general corporate purposes including funding future development of the properties.

Hedge Position

As of June 30, 2016, we had entered into hedging contracts for July 1, 2016 through December 31, 2022 for approximately 3.3 Tcf of our projected natural gas production at a weighted average index price of $3.72 per MMbtu and 745 million gallons of propane at a weighted average price of $0.48 per gallon. These hedging contracts include contracts for the remaining six months ended December 31, 2016 of approximately 297 Bcf of natural gas at a weighted average index price of $3.93 per Mcf and 232 million gallons of propane at a weighted average price of $0.59 per gallon.

Credit Facilities

As of June 30, 2016, the borrowing base under our revolving credit facility was $4.5 billion and lender commitments were $4.0 billion. The borrowing base under our revolving credit facility is redetermined semi-annually and is based on the estimated future cash flows from our proved oil and gas reserves and our commodity hedge positions. The next redetermination is scheduled to occur in October 2016. At June 30, 2016, we had $140 million of borrowings and $708 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 $1.5 billion. At June 30, 2016, Antero Midstream had $760 million of borrowings outstanding under its revolving credit facility. The facility will mature in November 2019. See "—Debt Agreements and Contractual Obligations—Midstream Credit Facility" for a description of this revolving credit facility.

2016 Capital Budget

For the six months ended June 30, 2016, our consolidated capital expenditures were approximately $945 million, including drilling and completion costs of $710 million, gathering and compression costs of Antero Midstream of $97 million, water handling and treatment costs of Antero Midstream of $79 million, $58 million of leasehold costs, and other capital expenditures of $1 million. Our capital budget for drilling, completions, and land for 2016 is $1.4 billion and includes: $1.3 billion for drilling and completion and $100 million for core leasehold acreage costs. We do not budget for acquisitions, and the June 9, 2016 agreement to acquire additional Marcellus acreage was not contemplated in the 2016 capital budget for leasehold acreage. Approximately 75% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 25% is allocated to the Utica Shale. During 2016, we plan to operate an average of 5 drilling rigs in the Marcellus Shale and 2 drilling rigs in the Utica Shale. Additionally, the capital budget for Antero Midstream for 2016 is $435 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.

Results of Operations

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2016

The Company has four operating segments: (1) the exploration and production of natural gas, NGLs, and oil; (2) gathering and compression; (3) water handling and treatment; and (4) marketing. Revenues from the gathering and compression and water handling and treatment segments are primarily derived from intersegment transactions for services provided to our exploration and production segment by Antero Midstream. 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 of the Company's reportable segments, including Segment Adjusted EBITDAX, were as follows for the three months ended June 30, 2015 and 2016 (in thousands):

	Exploration and production	Gathering and compression	Water handling and treatment	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)
Segment Adjusted EBITDAX (1)	256,825	40,772	23,000	(29,224)	(23,181)	268,192

	Exploration and production	Gathering and compression	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2016:						
Sales and revenues:						
Third-party	$ (343,394)	3,131	163	90,902	—	(249,198)
Intersegment	3,899	68,785	64,730	—	(137,414)	—
Total	$ (339,495)	71,916	64,893	90,902	(137,414)	(249,198)
Operating expenses:						
Lease operating	$ 12,257	—	34,317	—	(34,531)	12,043
Gathering, compression, processing, and transportation	267,738	6,997	—	—	(68,675)	206,060
Depletion, depreciation, and amortization	173,015	17,172	7,175	—	—	197,362
General and administrative expense (before equity-based compensation)	28,145	4,836	1,676	—	(371)	34,286
Equity-based compensation expense	19,022	5,302	1,492	—	—	25,816
Other operating expenses	37,848	450	4,294	125,977	(3,461)	165,108
Total	538,025	34,757	48,954	125,977	(107,038)	640,675
Operating income (loss)	$ (877,520)	37,159	15,939	(35,075)	(30,376)	(889,873)
Segment Adjusted EBITDAX (1)	309,863	59,633	28,067	(35,075)	(30,376)	332,112

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

The following tables set forth selected operating data for the three months ended June 30, 2015 compared to the three months ended June 30, 2016:

(in thousands)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2016	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 242,065	$ 229,787	$ (12,278)	(5)%
NGLs sales	59,525	94,713	35,188	59 %
Oil sales	23,032	16,740	(6,292)	(27)%
Gathering, compression, and water handling and treatment	4,490	3,294	(1,196)	(27)%
Marketing	49,829	90,902	41,073	82 %
Commodity derivative fair value losses	(2,227)	(684,634)	(682,407)	30,642 %
Total operating revenues	376,714	(249,198)	(625,912)	* %
Operating expenses:				
Lease operating	6,673	12,043	5,370	80 %
Gathering, compression, processing, and transportation	166,669	206,060	39,391	24 %
Production and ad valorem taxes	22,519	17,458	(5,061)	(22)%
Marketing	79,053	125,977	46,924	59 %
Exploration	628	1,109	481	77 %
Impairment of unproved properties	26,339	19,944	(6,395)	(24)%
Depletion, depreciation, and amortization	177,046	197,362	20,316	11 %
Accretion of asset retirement obligations	408	620	212	52 %
General and administrative (before equity-based compensation)	31,609	34,286	2,677	8 %
Equity-based compensation	27,582	25,816	(1,766)	(6)%
Contract termination and rig stacking	1,937	—	(1,937)	*
Total operating expenses	540,463	640,675	100,212	19 %
Operating loss	(163,749)	(889,873)	(726,124)	443 %
Other earnings (expenses):				
Equity in earnings of unconsolidated affiliate	—	484	484	* %
Interest expense	(59,823)	(62,595)	(2,772)	5 %
Loss before income taxes	(223,572)	(951,984)	(728,412)	326 %
Income tax benefit	84,089	376,494	292,405	348 %
Net loss and comprehensive loss including noncontrolling interest	(139,483)	(575,490)	(436,007)	313 %
Net income and comprehensive income attributable to noncontrolling interest	5,890	20,754	14,864	252 %
Net loss and comprehensive loss attributable to Antero Resources Corporation	$ (145,373)	$ (596,244)	$ (450,871)	310 %
Adjusted EBITDAX (1)	$ 268,192	$ 332,112	$ 63,920	24 %

(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) including noncontrolling interest and net cash provided by operating activities.

* Not meaningful or applicable.

	Three Months Ended June 30, 2015	2016	Amount of Increase (Decrease)	Percent Change
Production data:				
Natural gas (Bcf)	110	119	9	9 %
C2 Ethane (MBbl)	—	1,581	1,581	*
C3+ NGLs (MBbl)	3,655	4,771	1,116	31 %
Oil (MBbl)	523	477	(46)	(9)%
Combined (Bcfe)	135	160	25	19 %
Daily combined production (MMcfe/d)	1,484	1,762	278	19 %
Average prices before effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 2.20	$ 1.93	$ (0.27)	(12)%
C2 Ethane (per Bbl)	$ —	$ 8.36	$ 8.36	*
C3+ NGLs (per Bbl)	$ 16.29	$ 17.08	$ 0.79	5 %
Oil (per Bbl)	$ 44.06	$ 35.08	$ (8.98)	(20)%
Combined (per Mcfe)	$ 2.40	$ 2.13	$ (0.27)	(11)%
Average realized prices after effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 3.86	$ 4.31	$ 0.45	12 %
C2 Ethane (per Bbl)	$ —	$ 8.36	$ 8.36	*
C3+ NGLs (per Bbl)	$ 19.51	$ 18.98	$ (0.53)	(3)%
Oil (per Bbl)	$ 47.33	$ 35.08	$ (12.25)	(26)%
Combined (per Mcfe)	$ 3.85	$ 3.95	$ 0.10	3 %
Average Costs (per Mcfe):				
Lease operating	$ 0.05	$ 0.08	$ 0.03	60 %
Gathering, compression, processing, and transportation	$ 1.23	$ 1.29	$ 0.06	5 %
Production and ad valorem taxes	$ 0.17	$ 0.11	$ (0.06)	(35)%
Marketing, net	$ 0.22	$ 0.22	$ —	— %
Depletion, depreciation, amortization, and accretion	$ 1.31	$ 1.23	$ (0.08)	(6)%
General and administrative (before equity-based compensation)	$ 0.23	$ 0.21	$ (0.02)	(9)%

(2) Average sales prices shown in the table reflect both the before and after effects of our settled derivatives. Our calculation of such after effects includes gains on settlements of 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 Exploration and Production Results for the Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2016

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $325 million for the three months ended June 30, 2015 to $341 million for the three months ended June 30, 2016, an increase of $16 million, or 5%. Our production increased by 19% over that same period, from 135 Bcfe, or 1,484 MMcfe per day, for the three months ended June 30, 2015 to 160 Bcfe, or 1,762 MMcfe per day, for the three months ended June 30, 2016. Net equivalent prices before the effects of settled derivative gains decreased from $2.40 per Mcfe for the three months ended June 30, 2015 to $2.13 for the three months ended June 30, 2016, a decrease of 11%. Prices for natural gas and oil declined from 2015 levels, whereas prices for C3+ NGLs increased from 2015 levels. Net equivalent prices after the effects of gains on settled derivatives increased from $3.85 for the three months ended June 30, 2015 to $3.95 for the three months ended June 30, 2016.

Increased production volumes accounted for an approximate $61 million increase in year-over-year product revenues (calculated as the change in year-to-year volumes times the prior year average price), and changes in our equivalent prices accounted for an approximate $45 million decrease in year-over-year product 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 drilling and completion program. Based on our current drilling and completion plans for the remainder of 2016 and the increasing size of our production base, the rate of growth in our production will decline from the rate of growth realized in recent years.

Commodity derivative fair value losses. To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our production can be secured. 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. For the three months ended June 30, 2015 and 2016, our hedges resulted in derivative fair value losses of $2 million and $685 million, respectively. The derivative fair value losses were partially offset by $196 million and $293 million of gains on settled derivatives for the three months ended June 30, 2015 and 2016, respectively. Commodity derivative fair value gains or losses 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 and NGLs futures 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 handling and treatment revenues. Gathering, compression, and water handling and treatment revenues decreased from $4 million (net of intercompany eliminations of $83 million) for the three months ended June 30, 2015 to $3 million (net of intercompany eliminations of $134 million) for the three months ended June 30, 2016, primarily attributable to the provision of fresh water distribution services to wells in which we hold a higher working interest than the wells to which such services were provided in 2015. Fees for water distribution services provided to us by Antero Midstream are eliminated in consolidation. The amounts that are not eliminated 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 services provided by Antero Midstream.

Lease operating expense. Lease operating expenses increased from $7 million (net of intercompany eliminations of $6 million) for the three months ended June 30, 2015 to $12 million (net of intercompany eliminations of $35 million) for the three months ended June 30, 2016, an increase of 80%. The increase is primarily a result of an increase in the number of producing wells. On a per unit basis, lease operating expenses increased from $0.05 per Mcfe for the three months ended June 30, 2015 to $0.08 for the three months ended June 30, 2016 as a larger proportion of wells have been on production for longer periods of time compared to the prior year. Lease operating expenses are expected to slowly increase on a per unit basis as properties mature and average production per well declines.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expenses increased from $167 million (net of intercompany eliminations of $54 million) for the three months ended June 30, 2015 to $206 million (net of intercompany eliminations of $69 million) for the three months ended June 30, 2016. The increase in these expenses is a result of the increase in production and the related firm transportation costs, and third-party gathering, compression, and processing expenses. On a per Mcfe basis, total gathering, compression, processing and transportation expenses increased from $1.23 per Mcfe for the three months ended June 30, 2015 to $1.29 for the three months ended June 30, 2016, primarily due to higher transportation costs incurred on new pipelines that were placed in service in late 2015. Substantially all of the new pipelines currently deliver our gas to better price indices or sales contracts resulting in higher realized gas prices for the period.

Production and ad valorem tax expense. Total production and ad valorem taxes decreased from $23 million for the three months ended June 30, 2015 to $17 million for the three months ended June 30, 2016, primarily as a result of a decrease in production revenues. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging decreased from 6.9% for the three months ended June 30, 2015 to 5.1% for the three months ended June 30, 2016. As production in Ohio increased at a higher rate than West Virginia, severance taxes as a percentage of revenue decreased due to lower severance tax rates in Ohio as compared to West Virginia.

Exploration expense. Exploration expense increased from $0.6 million for the three months ended June 30, 2015 to $1.1 million for the three months ended June 30, 2016. These amounts represent expenses incurred for unsuccessful lease acquisitions.

Impairment of unproved properties. Impairment of unproved properties decreased from $26 million for the months ended June 30, 2015 to $20 million for the three months ended June 30, 2016, primarily due to a group of leases that we decided not to retain and develop during the three months ended June 30, 2015. 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.

DD&A. DD&A increased from $177 million for the three months ended June 30, 2015 to $197 million for the three months ended June 30, 2016, primarily because of increased production. DD&A per Mcfe decreased by 6%, from $1.31 per Mcfe during the three months ended June 30, 2015 to $1.23 per Mcfe during the three months ended June 30, 2016, primarily due to decreases in our per-unit development costs, in part due to recent well cost reductions that we have achieved.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a field-by-field basis whenever events or changes in circumstances (such as the decline in commodity prices since late 2014) indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeded the estimated undiscounted future cash flows (measured using futures prices at the end of a quarter), we would further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties. Due to the commodity price environment at June 30, 2016, we compared the carrying values of our proved properties to estimated future cash flows. As estimated future cash flows remained higher than the carrying value of our properties at June 30, 2016, we did not further evaluate our proved properties for impairment.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased from $32 million for the three months ended June 30, 2015 to $34 million for the three months ended June 30, 2016, primarily as a result of increases in legal and other general corporate expenses, largely as a result of our increase in development activities and production levels. On a per unit basis, general and administrative expense before equity-based compensation decreased by 9%, from $0.23 per Mcfe during the three months ended June 30, 2015 to $0.21 per Mcfe during the three months ended June 30, 2016, primarily due to our 19% increase in production. We had 472 employees as of June 30, 2015 and 499 employees as of June 30, 2016.

Noncash equity-based compensation expense decreased from $28 million for the three months ended June 30, 2015 to $26 million for the three months ended June 30, 2016 as a result of a $12 million decrease in amortization of expense related to the vesting of profits interests that became fully vested in October 2015, partially offset by a $8 million increase in equity-based compensation related to restricted stock unit awards and a $2 million increase in equity-based compensation related to performance share unit, stock option, and Antero Midstream phantom unit awards. See note 6 to the condensed consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Contract termination and rig stacking. We incurred contract termination and rig stacking costs of $2 million during the three months ended June 30, 2015. These costs represent fees incurred upon the delay or cancellation of drilling contracts with third-party contractors. We undertook these actions in order to align our drilling and completion activity level for 2015 with our 2015 capital budget. There were no such costs incurred during the three months ended June 30, 2016.

Equity in earnings of unconsolidated affiliate. In May 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline. Equity in earnings of unconsolidated affiliate represents the portion of the pipeline's net income which is allocated to Antero Midstream based on its equity interest in the pipeline. The Company did not hold any unconsolidated equity investments during the three months ended June 30, 2015.

Interest expense. Interest expense increased from $60 million for the three months ended June 30, 2015 to $63 million for the three months ended June 30, 2016, primarily due to increased average indebtedness. Interest expense includes approximately $2.6 million and $2.9 million of non-cash amortization of deferred financing costs for the three months ended June 30, 2015 and 2016, respectively.

Income tax benefit. Income tax benefit increased from $84 million for the three months ended June 30, 2015 to $376 million for the three months ended June 30, 2016 because of the increase in our pre-tax loss compared to the prior year period. The effect of state taxes and the noncontrolling interest in Antero Midstream largely account for the difference between the federal tax rate of 35% and the rate at which the income tax benefit was provided for the three months ended June 30, 2016.

At December 31, 2015, we had approximately $1.4 billion of U.S. federal NOLs and approximately $1.2 billion of state NOLs, which expire from 2024 through 2035. 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, 2016 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, 2016, we have accrued approximately $2.0 million of interest on unrecognized tax benefits.

Adjusted EBITDAX. Adjusted EBITDAX increased from $268 million for the three months ended June 30, 2015 to $332 million for the three months ended June 30, 2016, an increase of 24%. The increase in Adjusted EBITDAX was primarily due to a 19% increase in production, as well as a 3% increase in the average per Mcfe price received after the impact of cash settled derivatives, partially offset by increases in cash operating and gathering, compression, processing, and transportation 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 from continuing operations including noncontrolling interest and net cash provided by operating activities.

Discussion of Segment Results for the Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2016

Gathering and Compression. Revenue for the gathering and compression segment increased from $57 million for the three months ended June 30, 2015 to $72 million for the three months ended June 30, 2016, an increase of $15 million, or 27%. Gathering revenues increased by $11 million from the prior year period and compression revenues increased by $4 million as additional wells on production increased throughput volumes. Total operating expenses related to gathering and compression decreased from $37 million for the three months ended June 30, 2015 to $35 million for the three months ended June 30, 2016 primarily as a result of a decrease in the estimate of ad valorem taxes payable, partially offset by increases in depreciation expense due to an increase in gathering and compression assets.

Water Handling and Treatment. Revenue for the water handling and treatment segment increased from $31 million for the three months ended June 30, 2015 to $65 million for the three months ended June 30, 2016, an increase of $34 million, or 112%. The increase was primarily due to revenues generated from waste water treatment services that commenced in the fourth quarter of 2015, as well as increased use of the water systems as a result of increased completion activity. The volume of water delivered through the systems increased from 8.7 MMBbls for the three months ended June 30, 2015 to 9.6 MMBbls for the three months ended June 30, 2016. Operating expenses for the water handling and treatment segment increased from $15 million for the three months ended June 30, 2015 to $49 million for the three months ended June 30, 2016 as a result of expenses related to waste water treatment services, accretion expense related to the contingent acquisition consideration payable by Antero Midstream in connection with Antero's dropdown of its water handling and treatment assets to Antero Midstream in September 2015, and an increase in depreciation expense due to an increase in fresh water distribution assets.

Marketing. Where permitted, we purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity, or engage third parties to conduct these activities on our behalf, in order to optimize the revenues from these transportation agreements. We have entered into long-term firm transportation agreements for a significant portion of our current and expected future production in order to secure guaranteed capacity to favorable markets. Marketing revenues of $50 million and $91 million and expenses of $79 million and $126 million for the three months ended June 30, 2015 and 2016, respectively, relate to these activities. Net losses on our marketing activities were $29 million and $35 million for the three months ended June 30, 2015 and 2016, 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 $30 million and $36 million for the three months ended June 30, 2015 and 2016, respectively, related to unutilized excess capacity which increased due to new firm transportation agreements. Based on current projections for our 2016 annual production levels, we estimate that we could incur total annual net marketing expense of $95 million to $125 million in 2016 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 between various indices. In years subsequent to 2016, our commitments and obligations under firm transportation agreements continue to increase. As a result, our net marketing expense could continue to increase depending on utilization of our transportation capacity based on future production and how much, if any, future excess transportation can be marketed to third parties.

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2016

The Company has four operating segments: (1) the exploration and production of natural gas, NGLs, and oil; (2) gathering and compression; (3) water handling and treatment; and (4) marketing. Revenues from the gathering and compression and water handling and treatment segments are primarily derived from intersegment transactions for services provided to our exploration and production segment by Antero Midstream. 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 of the Company's reportable segments, including Adjusted EBITDAX, were as follows for the six months ended June 30, 2015 and 2016 (in thousands):

	Exploration and production	Gathering and compression	Water handling and treatment	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
Segment Adjusted EBITDAX (1)	589,903	76,448	48,556	(44,793)	(47,311)	622,803

	Exploration and production	Gathering and compression	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2016:						
Sales and revenues:						
Third-party	$ 274,550	6,718	420	190,118	—	471,806
Intersegment	7,724	134,825	130,919	—	(273,468)	—
Total	$ 282,274	141,543	131,339	190,118	(273,468)	471,806
Operating expenses:						
Lease operating	$ 23,589	—	75,031	—	(75,284)	23,336
Gathering, compression, processing, and transportation	535,183	14,167	—	—	(134,552)	414,798
Depletion, depreciation, and amortization	340,567	34,240	14,137	—	—	388,944
General and administrative expense (before equity-based compensation)	54,199	9,785	3,846	—	(727)	67,103
Equity-based compensation expense	36,520	9,688	3,078	—	—	49,286
Other operating expenses	73,013	899	8,498	263,910	(6,857)	339,463
Total	1,063,071	68,779	104,590	263,910	(217,420)	1,282,930
Operating income (loss)	$ (780,797)	72,764	26,749	(73,792)	(56,048)	(811,124)
Segment Adjusted EBITDAX (1)	649,840	116,692	50,821	(73,792)	(56,048)	687,513

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

The following tables set forth selected operating data for the six months ended June 30, 2015 compared to the six months ended June 30, 2016:

(in thousands)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2016	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 557,007	$ 484,563	$ (72,444)	(13)%
NGLs sales	138,311	167,778	29,467	21 %
Oil sales	35,489	26,919	(8,570)	(24)%
Gathering, compression, and water handling and treatment	10,658	7,138	(3,520)	(33)%
Marketing	107,609	190,118	82,509	77 %
Commodity derivative fair value gains (losses)	757,327	(404,710)	(1,162,037)	(153)%
Total operating revenues	1,606,401	471,806	(1,134,595)	(71)%
Operating expenses:				
Lease operating	14,775	23,336	8,561	58 %
Gathering, compression, processing, and transportation	330,331	414,798	84,467	26 %
Production and ad valorem taxes	46,737	36,742	(9,995)	(21)%
Marketing	152,402	263,910	111,508	73 %
Exploration	1,999	2,123	124	6 %
Impairment of unproved properties	34,916	35,470	554	2 %
Depletion, depreciation, and amortization	359,346	388,944	29,598	8 %
Accretion of asset retirement obligations	808	1,218	410	51 %
General and administrative (before equity-based compensation)	62,875	67,103	4,228	7 %
Equity-based compensation	55,365	49,286	(6,079)	(11)%
Contract termination and rig stacking	10,902	—	(10,902)	*
Total operating expenses	1,070,456	1,282,930	212,474	20 %
Operating income (loss)	535,945	(811,124)	(1,347,069)	* %
Other earnings (expenses):				
Equity in earnings of unconsolidated affiliate	—	484	484	* %
Interest expense	(113,008)	(125,879)	(12,871)	11 %
Income (loss) before income taxes	422,937	(936,519)	(1,359,456)	* %
Income tax (expense) benefit	(163,249)	371,679	534,928	* %
Net income (loss) and comprehensive income (loss) including noncontrolling interest	259,688	(564,840)	(824,528)	* %
Net income and comprehensive income attributable to noncontrolling interest	10,630	36,459	25,829	243 %
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 249,058	$ (601,299)	$ (850,357)	*
Adjusted EBITDAX (1)	$ 622,803	$ 687,513	$ 64,710	10 %

(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) including noncontrolling interest and net cash provided by operating activities.

* Not meaningful or applicable.

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2016	Amount of Increase (Decrease)	Percent Change
Production data:				
Natural gas (Bcf)	222	242	20	9 %
C2 Ethane (MBbl)	—	2,662	2,662	*
C3+ NGLs (MBbl)	6,895	9,452	2,557	37 %
Oil (MBbl)	889	949	61	7 %
Combined (Bcfe)	269	320	52	19 %
Daily combined production (MMcfe/d)	1,485	1,760	275	19 %
Average prices before effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 2.51	$ 2.00	$ (0.51)	(20)%
C2 Ethane (per Bbl)	$ —	$ 7.68	$ 7.68	*
C3+ NGLs (per Bbl)	$ 20.06	$ 15.59	$ (4.47)	(22)%
Oil (per Bbl)	$ 39.93	$ 28.36	$ (11.57)	(29)%
Combined (per Mcfe)	$ 2.72	$ 2.12	$ (0.60)	(22)%
Average realized prices after effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 4.12	$ 4.42	$ 0.30	7 %
C2 Ethane (per Bbl)	$ —	$ 7.68	$ 7.68	*
C3+ NGLs (per Bbl)	$ 22.66	$ 18.93	$ (3.73)	(16)%
Oil (per Bbl)	$ 46.40	$ 28.36	$ (18.04)	(39)%
Combined (per Mcfe)	$ 4.14	$ 4.05	$ (0.09)	(2)%
Average Costs (per Mcfe):				
Lease operating	$ 0.05	$ 0.07	$ 0.02	40 %
Gathering, compression, processing, and transportation	$ 1.23	$ 1.29	$ 0.06	5 %
Production and ad valorem taxes	$ 0.17	$ 0.11	$ (0.06)	(35)%
Marketing, net	$ 0.17	$ 0.23	$ 0.06	35 %
Depletion, depreciation, amortization, and accretion	$ 1.34	$ 1.22	$ (0.12)	(9)%
General and administrative (before equity-based compensation)	$ 0.23	$ 0.21	$ (0.02)	(9)%

(2) Average sales prices shown in the table reflect both the before and after effects of our settled derivatives. Our calculation of such after effects includes gains on settlements of 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 Exploration and Production Results for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2016

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil decreased from $731 million for the six months ended June 30, 2015 to $679 million for the six months ended June 30, 2016, a decrease of $52 million, or 7%. Our production increased by 19% over that same period, from 269 Bcfe, or 1,485 MMcfe per day, for the six months ended June 30, 2015 to 320 Bcfe, or 1,760 MMcfe per day, for the six months ended June 30, 2016. Net equivalent prices before the effects of settled derivative gains decreased from $2.72 per Mcfe for the six months ended June 30, 2015 to $2.12 for the six months ended June 30, 2016, a decrease of 22%. Prices for natural gas, NGLs, and oil all declined from 2015 levels. Net equivalent prices after the effects of gains on settled derivatives decreased from $4.14 for the six months ended June 30, 2015 to $4.05 for the six months ended June 30, 2016.

Increased production volumes accounted for an approximate $140 million increase in year-over-year product revenues (calculated as the change in year-to-year volumes times the prior year average price), and changes in our equivalent prices accounted for an approximate $192 million decrease in year-over-year product 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 drilling and completion program. Based on our current drilling and completion plans for the remainder of 2016 and the increasing size of our production base, the rate of growth in our production will decline from the rate of growth realized in recent years.

Commodity derivative fair value gains (losses). To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our production can be secured. 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. For the six months ended June 30, 2015 and 2016, our hedges resulted in derivative fair value gains (losses) of $757 million and $(405)

million, respectively. The derivative fair value gains and losses included $381 million and $617 million of gains on settled derivatives for the six months ended June 30, 2015 and 2016, respectively.

Commodity derivative fair value gains or losses 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 and NGLs futures 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 handling and treatment revenues. Gathering, compression, and water handling and treatment revenues decreased from $11 million (net of intercompany eliminations of $163 million) for the six months ended June 30, 2015 to $7 million (net of intercompany eliminations of $266 million) for the six months ended June 30, 2016 primarily attributable to the provision of fresh water distribution services to wells in which we hold a higher working interest than the wells to which such services were provided in 2015. Fees for water distribution services provided to us by Antero Midstream are eliminated in consolidation. The amounts that are not eliminated 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 services provided by Antero Midstream.

Lease operating expense. Lease operating expenses increased from $15 million (net of intercompany eliminations of $12 million) for the six months ended June 30, 2015 to $23 million (net of intercompany eliminations of $75 million) for the six months ended June 30, 2016, an increase of 58%. The increase is primarily a result of an increase in the number of producing wells. On a per unit basis, lease operating expenses increased from $0.05 per Mcfe for the six months ended June 30, 2015 to $0.07 for the six months ended June 30, 2016 as a larger proportion of wells have been on production for longer periods of time compared to the prior year. Lease operating expenses are expected to slowly increase on a per unit basis as properties mature and average production per well declines.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expenses increased from $330 million (net of intercompany eliminations of $104 million) for the six months ended June 30, 2015 to $415 million (net of intercompany eliminations of $135 million) for the six months ended June 30, 2016. The increase in these expenses is a result of the increase in production and the related firm transportation costs, and third-party gathering, compression, and processing expenses. On a per Mcfe basis, total gathering, compression, processing and transportation expenses increased from $1.23 per Mcfe for the six months ended June 30, 2015 to $1.29 for the six months ended June 30, 2016, primarily due to higher transportation costs incurred on new pipelines that were placed in service in late 2015. Substantially all of the new pipelines currently deliver our gas to better price indices or sales contracts resulting in higher realized gas prices for the period.

Production and ad valorem tax expense. Total production and ad valorem taxes decreased from $47 million for the six months ended June 30, 2015 to $37 million for the six months ended June 30, 2016, primarily as a result of a decrease in production revenues. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging decreased from 6.4% for the six months ended June 30, 2015 to 5.4% for the six months ended June 30, 2016. As production in Ohio increased at a higher rate than West Virginia, severance taxes as a percentage of revenue decreased due to lower severance tax rates in Ohio as compared to West Virginia.

Exploration expense. Exploration expense remained consistent at $2 million for the six months ended June 30, 2015 and 2016. These amounts represent expenses incurred for unsuccessful lease acquisitions.

Impairment of unproved properties. Impairment of unproved properties remained consistent at $35 million for the six months ended June 30, 2015 and 2016. 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.

DD&A. DD&A increased from $359 million for the six months ended June 30, 2015 to $389 million for the six months ended June 30, 2016, primarily because of increased production. DD&A per Mcfe decreased by 9%, from $1.34 per Mcfe during the six months ended June 30, 2015 to $1.22 per Mcfe during the six months ended June 30, 2016, primarily due to decreases in our per-unit development costs, in part due to recent well cost reductions that we have achieved.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a field-by-field basis whenever events or changes in circumstances (such as the decline in commodity prices since late 2014) indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeded the estimated undiscounted future cash flows (measured using futures prices at the end of a quarter), we would further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties. Due to the commodity price environment at June 30, 2016, we compared the carrying values of our proved properties to estimated future cash flows. As estimated future cash flows remained higher than the carrying value of our properties at June 30, 2016, we did not further evaluate our proved properties for impairment.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased from $63 million for the six months ended June 30, 2015 to $67 million for the six months ended June 30, 2016, primarily as a result of increases in legal and other general corporate expenses, largely as a result of our increase in development activities and production levels. On a per unit basis, general and administrative expense before equity-based compensation decreased by 9%, from $0.23 per Mcfe during the six months ended June 30, 2015 to $0.21 per Mcfe during the six months ended June 30, 2016, primarily due to our 19% increase in production. We had 472 employees as of June 30, 2015 and 499 employees as of June 30, 2016.

Noncash equity-based compensation expense decreased from $55 million for the six months ended June 30, 2015 to $49 million for the six months ended June 30, 2016 as a result of a $27 million decrease in amortization of expense related to the vesting of profits interests that became fully vested in October 2015, partially offset by a $17 million increase in equity-based compensation related to restricted stock unit awards and a $4 million increase in equity-based compensation related to performance share unit, stock option, and Antero Midstream phantom unit awards. See note 6 to the condensed consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Contract termination and rig stacking. We incurred contract termination and rig stacking costs of $11 million during the six months ended June 30, 2015. These costs represent fees incurred upon the delay or cancellation of drilling contracts with third-party contractors. We undertook these actions in order to align our drilling and completion activity level for 2015 with our 2015 capital budget. There were no such costs incurred during the six months ended June 30, 2016.

Equity in earnings of unconsolidated affiliate. In May 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline. Equity in earnings of unconsolidated affiliate represents the portion of the pipeline's net income which is allocated to Antero Midstream based on its equity interest in the pipeline. The Company did not hold any unconsolidated equity investments during the six months ended June 30, 2015.

Interest expense. Interest expense increased from $113 million for the six months ended June 30, 2015 to $126 million for the six months ended June 30, 2016, primarily due to increased average indebtedness. Interest expense includes approximately $4.8 million and $5.7 million of non-cash amortization of deferred financing costs for the six months ended June 30, 2015 and 2016, respectively.

Income tax (expense) benefit. Income tax (expense) benefit changed from a deferred tax expense of $163 million for the six months ended June 30, 2015 to a deferred tax benefit of $372 million for the six months ended June 30, 2016. The deferred tax benefit in 2016 results from the loss incurred for financial reporting purposes in the six months ended June 30, 2016, resulting in a decrease in deferred tax liabilities. The effect of state taxes and the noncontrolling interest in Antero Midstream largely account for the difference between the federal tax rate of 35% and the rate at which the income tax benefit was provided for the six months ended June 30, 2016.

At December 31, 2015, we had approximately $1.4 billion of U.S. federal NOLs and approximately $1.2 billion of state NOLs, which expire from 2024 through 2035. 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, 2016 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, 2016, we have accrued approximately $2.0 million of interest on unrecognized tax benefits.

Adjusted EBITDAX. Adjusted EBITDAX increased from $623 million for the six months ended June 30, 2015 to $688 million for the six months ended June 30, 2016, an increase of 10%. The increase in Adjusted EBITDAX was primarily due to a 19% increase in production, which was partially offset by a 2% decrease in the average per Mcfe price received after the impact of cash settled derivatives, as well as increases in cash operating and gathering, compression, processing, and transportation 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 from continuing operations including noncontrolling interest and net cash provided by operating activities.

Discussion of Segment Results for the Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2016

Gathering and Compression. Revenue for the gathering and compression segment increased from $109 million for the six months ended June 30, 2015 to $142 million for the six months ended June 30, 2016, an increase of $33 million, or 30%. Gathering revenues increased by $24 million from the prior year period and compression revenues increased by $8 million as additional wells on production increased throughput volumes. Total operating expenses related to gathering and compression decreased from $72 million for the six months ended June 30, 2015 to $69 million for the six months ended June 30, 2016 primarily as a result of a decrease in the estimate of ad valorem taxes payable, partially offset by increases in depreciation expense due to an increase in gathering and compression assets.

Water Handling and Treatment. Revenue for the water handling and treatment segment increased from $65 million for the six months ended June 30, 2015 to $131 million for the six months ended June 30, 2016, an increase of $66 million, or 102%. The increase was primarily due to revenues generated from waste water treatment services that commenced in the fourth quarter of 2015, as well as increased use of the water systems as a result of increased completion activity. The volume of water delivered through the systems increased from 17.9 MMBbls for the six months ended June 30, 2015 to 18.4 MMBbls for the six months ended June 30, 2016. Operating expenses for the water handling and treatment segment increased from $31 million for the six months ended June 30, 2015 to $105 million for the six months ended June 30, 2016 as a result of expenses related to waste water treatment services, accretion expense related to the contingent acquisition consideration payable by Antero Midstream in connection with Antero's dropdown of its water handling and treatment assets to Antero Midstream in September 2015, and an increase in depreciation expense due to an increase in fresh water distribution assets.

Marketing. Where permitted, we purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity, or engage third parties to conduct these activities on our behalf, in order to optimize the revenues from these transportation agreements. We have entered into long-term firm transportation agreements for a significant portion of our current and expected future production in order to secure guaranteed capacity to favorable markets. Marketing revenues of $108 million and $190 million and expenses of $152 million and $264 million for the six months ended June 30, 2015 and 2016, respectively, relate to these activities. Net losses on our marketing activities were $44 million and $74 million for the six months ended June 30, 2015 and 2016, 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 $45 million and $72 million for the six months ended June 30, 2015 and 2016, respectively, related to unutilized excess capacity which increased due to new firm transportation agreements. Based on current projections for our 2016 annual production levels, we estimate that we could incur total annual net marketing expense of $95 million to $125 million in 2016 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 between various indices. In years subsequent to 2016, our commitments and obligations under firm transportation agreements continue to increase. As a result, our net marketing expense could continue to increase depending on utilization of our transportation capacity based on future production and how much, if any, future excess transportation can be marketed to third parties.

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been issuances of debt and equity securities, borrowings under our revolving credit facility, asset sales, and net cash provided by operating activities. 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 development of gathering, compression, and water handling and treatment infrastructure. In August 2015, we commenced site preparation and construction on an advanced waste water treatment complex in West Virginia, which was contributed to Antero Midstream in connection with the contribution of our water handling and treatment assets. 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, or capital market transactions, 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, 2015 and 2016:

	Six Months Ended June 30,	
(in thousands)	2015	2016
Net cash provided by operating activities	595,108	578,706
Net cash used in investing activities	(1,338,778)	(1,038,359)
Net cash provided by financing activities	640,977	464,431
Net increase (decrease) in cash and cash equivalents	(102,693)	4,778

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $595 million and $579 million for the six months ended June 30, 2015 and 2016, respectively. The decrease in cash flows from operations from the six months ended June 30, 2015 to the six months ended June 30, 2016 was primarily the result of increases in cash operating costs, interest expense, and changes in working capital levels, net of increases in total realized revenues from production and settled derivatives.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of natural gas, NGLs, and oil prices, as well as volatility in the cash flows attributable to settlement of our commodity derivatives. Prices for natural gas, NGLs, and oil 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, 2016, we used cash totaling $1.0 billion in investing activities, including $710 million for drilling and completion costs, $58 million for undeveloped leasehold additions, $79 million by Antero Midstream for water handling and treatment systems, $97 million by Antero Midstream for gathering and compression systems, and $1 million for other property and equipment. 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 additions, $34 million for water handling systems, $200 million for gathering and compression systems, and $3 million for other property and equipment.

Our board of directors has approved a capital budget of $1.4 billion for 2016, which does not include the capital budget of $435 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 to 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 commodity 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, 2016 of $464 million consisted of net proceeds of $753 million from the issuance of common stock, proceeds of $178 million from the sale of Antero Midstream common units owned by Antero, partially offset by net repayments on our revolving credit facilities of $427 million, distributions of $32 million to noncontrolling interest owners in Antero Midstream, and other items totaling $8 million. Proceeds from the issuance of common stock have been primarily used to reduce amounts outstanding under the revolving credit facility until the leasehold acquisition, for which the stock was issued, is closed. The leasehold acquisition is expected to close in the third quarter of 2016. 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.

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 assets and are subject to regular semiannual redeterminations. At June 30, 2016, the borrowing base was $4.5 billion and lender commitments were $4.0 billion. The next redetermination of the borrowing base is scheduled to occur in October 2016. At June 30, 2016, we had $140 million of borrowings and $708 million of letters of credit outstanding under the Credit Facility, with a weighted average interest rate of 2.00%. At December 31, 2015, we had $707 million of borrowings and $702 million of letters of credit outstanding under the Credit Facility, with a weighted average interest rate of 2.32%. The Credit Facility matures on May 5, 2019.

Principal amounts borrowed on the Credit 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. 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 contains 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 also requires Antero and its restricted subsidiaries 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, 2015 and June 30, 2016. The actual borrowing capacity available to us may be limited by the financial ratio covenants. At June 30, 2016, our current ratio was 7.45 to 1.0 (based on the $4.5 billion borrowing base as of June 30, 2016) and our interest coverage ratio was 5.07 to 1.0.

Midstream Credit Facility. Antero Midstream has a secured 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 $1.5 billion and for a letter of credit sublimit of $150 million. At June 30, 2016, Antero Midstream had a total outstanding balance under the Midstream Facility of $760 million, with a weighted average interest rate of 1.96%. At December 31, 2015, Antero Midstream had a total outstanding balance under the Midstream Facility of $620 million, with a weighted average interest rate of 1.92%. The Midstream Facility matures 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 and water handling and treatment services to Antero 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 (annualized until the fiscal quarter ending September 30, 2016), of not more than 5.00 to 1.0 at the end of each quarter; 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, 2015 and June 30, 2016.

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 to the extent of the value of the collateral securing the Credit Facility. 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 at redemption prices ranging from 104.50% currently to 100.00% on or after December 1, 2018. 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 to the extent of the value of the collateral securing the Credit Facility. The 2021 notes rank pari 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 to the extent of the value of the collateral securing the Credit Facility. The 2022 notes rank pari 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, 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 to the extent of the value of the collateral securing the Credit Facility. The 2023 notes rank pari 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, 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, 2015 and June 30, 2016.

We may, from time to time, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions, or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, and other factors. The amounts involved may be material.

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, 2017. At December 31, 2015 and June 30, 2016, there were no outstanding borrowings under this facility.

Contractual Obligations. A summary of our contractual obligations as of June 30, 2016 is provided in the table below. Contractual obligations listed exclude minimum fees that we will pay to Antero Midstream, our consolidated subsidiary, under gathering and compression, and water services agreements.

	Year Ended June 30,						
(in millions)	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Credit Facility(1)	$ —	—	140	—	—	—	140
Antero Midstream Partners LP Facility(1)	—	—	—	760	—	—	760
Senior notes—principal(2)	—	—	—	—	525	2,850	3,375
Senior notes—interest(2)	184	184	184	184	168	168	1,072
Drilling rig and completion service commitments(3)	106	98	86	17	—	—	307
Firm transportation (4)	508	840	1,014	1,073	1,076	10,469	14,980
Processing, gathering, and compression services (5)	343	320	211	186	185	783	2,028
Office and equipment leases	13	12	10	8	7	28	78
Asset retirement obligations(6)	—	—	—	—	—	35	35
Total	$ 1,154	1,454	1,645	2,228	1,961	14,333	22,775

(1) Includes outstanding principal amounts at June 30, 2016. This table does not include future commitment fees, interest expense or other fees on our Credit Facility or the Midstream 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 August 2016 through December 2019. 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 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 or 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, and excluding equity in earnings of unconsolidated affiliates. "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, and as a basis for strategic planning and forecasting. Adjusted EBITDAX, as defined by our Credit Facility, is used 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.

"Segment Adjusted EBITDAX" is also used by our management team for various purposes, including as a measure of operating performance and as a basis for strategic planning and forecasting. Segment Adjusted EBITDAX is a non-GAAP financial measure that we define as operating income before derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), 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, gain or loss on sale of assets, and gain or loss on contingent acquisition consideration accretion. Operating income represents net income, including noncontrolling interest, before interest expense and income taxes, and is the most directly comparable GAAP financial measure to Segment Adjusted EBITDAX because we do not account for income tax expense or interest expense on a segment basis. The following tables represent a reconciliation of our operating income to Segment Adjusted EBITDAX for the three and six months ended June 30, 2015 and 2016 (in thousands):

	Exploration and production	Gathering and compression	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2015:						
Operating income (loss)	(147,059)	20,086	15,629	(29,224)	(23,181)	(163,749)
Commodity derivative fair value losses	2,227	—	—	—	—	2,227
Gains on settled derivatives	195,880	—	—	—	—	195,880
Depletion, depreciation, amortization, and accretion	155,994	15,298	6,162	—	—	177,454
Impairment of unproved properties	26,339	—	—	—	—	26,339
Exploration expense	628	—	—	—	—	628
Equity-based compensation expense	20,985	5,388	1,209	—	—	27,582
State franchise taxes	(106)	—	—	—	—	(106)
Contract termination and rig stacking	1,937	—	—	—	—	1,937
Segment and consolidated Adjusted EBITDAX	$ 256,825	40,772	23,000	(29,224)	(23,181)	268,192

	Exploration and production	Gathering and compression	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Three months ended June 30, 2016:						
Operating income (loss)	(877,520)	37,159	15,939	(35,075)	(30,376)	(889,873)
Commodity derivative fair value losses	684,634	—	—	—	—	684,634
Gains on settled derivatives	292,500	—	—	—	—	292,500
Depletion, depreciation, amortization, and accretion	173,635	17,172	7,175	—	—	197,982
Impairment of unproved properties	19,944	—	—	—	—	19,944
Exploration expense	1,109	—	—	—	—	1,109
Loss (gain) on contingent acquisition consideration accretion	(3,461)	—	3,461	—	—	—
Equity-based compensation expense	19,022	5,302	1,492	—	—	25,816
State franchise taxes	—	—	—	—	—	—
Segment and consolidated Adjusted EBITDAX	$ 309,863	59,633	28,067	(35,075)	(30,376)	332,112

	Exploration and production	Gathering and compression	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2015:						
Operating income (loss)	557,676	36,464	33,909	(44,793)	(47,311)	535,945
Commodity derivative fair value gains	(757,327)	—	—	—	—	(757,327)
Gains on settled derivatives	380,720	—	—	—	—	380,720
Depletion, depreciation, amortization, and accretion	317,899	29,973	12,282	—	—	360,154
Impairment of unproved properties	34,916	—	—	—	—	34,916
Exploration expense	1,999	—	—	—	—	1,999
Equity-based compensation expense	42,989	10,011	2,365	—	—	55,365
State franchise taxes	129	—	—	—	—	129
Contract termination and rig stacking	10,902	—	—	—	—	10,902
Segment and consolidated Adjusted EBITDAX	$ 589,903	76,448	48,556	(44,793)	(47,311)	622,803

	Exploration and production	Gathering and compression	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Six months ended June 30, 2016:						
Operating income (loss)	(780,797)	72,764	26,749	(73,792)	(56,048)	(811,124)
Commodity derivative fair value losses	404,710	—	—	—	—	404,710
Gains on settled derivatives	616,847	—	—	—	—	616,847
Depletion, depreciation, amortization, and accretion	341,785	34,240	14,137	—	—	390,162
Impairment of unproved properties	35,470	—	—	—	—	35,470
Exploration expense	2,123	—	—	—	—	2,123
Loss (gain) on contingent acquisition consideration accretion	(6,857)	—	6,857	—	—	—
Equity-based compensation expense	36,520	9,688	3,078	—	—	49,286
State franchise taxes	39	—	—	—	—	39
Segment and consolidated Adjusted EBITDAX	$ 649,840	116,692	50,821	(73,792)	(56,048)	687,513

The following table represents a reconciliation of our net income from continuing operations, including noncontrolling interest, to total Segment and consolidated Adjusted EBITDAX from continuing operations and a reconciliation of our total Segment and consolidated 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)	**2015**	**2016**	**2015**	**2016**
Net income (loss) including noncontrolling interest	$ (139,483)	(575,490)	259,688	(564,840)
Commodity derivative fair value (gains) losses(1)	2,227	684,634	(757,327)	404,710
Gains on settled derivatives(1)	195,880	292,500	380,720	616,847
Interest expense	59,823	62,595	113,008	125,879
Income tax expense (benefit)	(84,089)	(376,494)	163,249	(371,679)
Depletion, depreciation, amortization, and accretion	177,454	197,982	360,154	390,162
Impairment of unproved properties	26,339	19,944	34,916	35,470
Exploration expense	628	1,109	1,999	2,123
Equity-based compensation expense	27,582	25,816	55,365	49,286
Equity in earnings of unconsolidated affiliate	—	(484)	—	(484)
State franchise taxes	(106)	—	129	39
Contract termination and rig stacking	1,937	—	10,902	—
Total Segment and consolidated Adjusted EBITDAX	268,192	332,112	622,803	687,513
Interest expense	(59,823)	(62,595)	(113,008)	(125,879)
Exploration expense	(628)	(1,109)	(1,999)	(2,123)
Changes in current assets and liabilities	35,361	(30,218)	94,344	18,612
State franchise taxes	106	—	(129)	(39)
Other non-cash items	460	348	(6,903)	622
Net cash provided by operating activities	$ 243,668	238,538	595,108	578,706

(1) The adjustments for the derivative fair value gains and losses and gains on settled derivatives have the effect of adjusting net income from operations for changes in the fair value of unsettled derivatives, which are recognized at the end of each accounting period. As a result, derivative gains included in the calculation of Adjusted EBITDAX only reflects 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 our production activities, estimates of natural gas, NGLs, and oil reserve quantities and standardized measures of future cash flows, and impairment of proved properties. We provide an expanded discussion of our more significant accounting policies, estimates and judgments in our 2015 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 2015 Form 10-K, for a discussion of additional accounting policies and estimates made by management.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. Under GAAP for successful efforts accounting, if the carrying amount exceeded the estimated undiscounted future net cash flows (measured using futures prices), we would estimate the fair value of our properties and record an impairment charge for any excess of the carrying amount of the properties over the estimated fair value of the properties. Given the rapid decline in the market prices of natural gas, NGLs, and oil that occurred during the fourth quarter of 2014 and continued through 2015 and into 2016, at June 30, 2016, we compared estimated undiscounted future cash flows using futures pricing for our Utica and Marcellus Basin properties to the carrying

value of those properties. Estimated undiscounted future cash flows exceeded the carrying values at June 30, 2016 and thus, no further evaluation of the fair value of the properties for impairment is required under GAAP. As a result, we have not recorded any impairment expenses associated with our Utica and Marcellus Basin proved properties during the three or six months ended June 30, 2016. Additionally, we did not record any impairment expenses for proved properties during the year ended December 31, 2015. Based on current futures commodity prices, we currently do not anticipate having to record any impairment charge for our proved properties in the near future. We are unable, however, to predict commodity prices with any greater precision than the futures market.

New Accounting Pronouncements

On May 28, 2014, the FASB issued 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 GAAP when it becomes effective. Additionally, on May 3, 2016, the FASB issued ASU No. 2016-11, which rescinds SEC accounting guidance regarding the use of the entitlements method for recognition of natural gas revenues. The new standards become effective for the Company on January 1, 2018. Early application is not permitted. The standards permit the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 and ASU No. 2016-11 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 standards on its ongoing financial reporting.

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases*, which requires all leasing arrangements to be presented in the balance sheet as liabilities along with a corresponding asset. The ASU will replace most existing leases guidance in GAAP when it becomes effective. The new standard becomes effective for the Company on January 1, 2019. Although early application is permitted, the Company does not plan to early adopt the ASU. The standard requires the use of the modified retrospective transition method. The Company is evaluating the effect that ASU 2016-02 will have on its consolidated financial statements and related disclosures and has not yet determined the effect of the standard on its ongoing financial reporting.

On June 16, 2016, the FASB issued ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires an entity to measure its financial assets at the net amount expected to be collected. The ASU will replace most existing guidance in GAAP regarding the valuation of financial assets when it becomes effective. The new standard becomes effective for the Company on January 1, 2020. 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, 2016, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rig and 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, as well as 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, historically, been volatile and unpredictable, 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 derivative instruments 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 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. These contracts may include commodity price swaps whereby we will receive a fixed price and pay a variable market price to the counterparty, commodity price swaps whereby we will pay a fixed price to the contract counterparty and receive a variable market price, cashless price collars that set a floor and ceiling price for the hedged production, or basis differential swaps. These contracts are financial instruments, and do not require or allow for physical delivery of the hedged commodity. The Company was not party to any collars as of or during the six months ended June 30, 2016.

At June 30, 2016, we had in place natural gas and NGLs swaps covering portions of our projected production from 2016 through 2022. Our commodity hedge position as of June 30, 2016 is summarized in note 8 to our condensed consolidated financial statements included elsewhere herein. 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, 2022. Based on our production and our fixed price swap contracts which settled during the six months ended June 30, 2016, our income before taxes would have decreased by approximately $2.5 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 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; therefore, 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 settled derivatives and derivative positions which remain open) within operating revenues as “Commodity derivative fair value gains.”

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, 2016, the estimated fair value of our commodity derivative instruments was a net asset of $2.1 billion comprised of current and noncurrent assets and current and noncurrent liabilities. At December 31, 2015, the estimated fair value of our commodity derivative instruments was a net asset of $3.1 billion comprised of current and noncurrent assets. None of these commodity derivative instruments were entered into for trading or speculative purposes.

By removing price volatility from a portion of our expected production through December 2022, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those 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 derivative contracts ($2.1 billion at June 30, 2016), the sale of our oil and gas production ($110 million at June 30, 2016) which we market to energy companies, end users and refineries, and joint interest receivables ($39 million at June 30, 2016).

By using derivative instruments that are not traded on an exchange to hedge our 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 fifteen different counterparties, all of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately $2.1 billion at June 30, 2016 includes the following values by bank counterparty: Morgan Stanley - $568 million; Barclays - $461 million; JP Morgan - $388 million; Wells Fargo - $204 million; Scotiabank - $148 million; Citigroup - $126 million; BNP Paribas - $81 million; Toronto Dominion - $51 million; Canadian Imperial Bank of Commerce - $30 million; Fifth Third - $24 million; Bank of Montreal - $13 million; SunTrust - $6 million; and Capital One - $4 million. The credit ratings of certain of these banks were downgraded in recent years because of their exposure to 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, 2016 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 the 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, 2016, 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 our billing of 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 the Midstream Facility of our consolidated subsidiary, Antero Midstream. Each of these credit facilities has a floating interest rate. The average annualized interest rate incurred on this indebtedness during the six months ended June 30, 2016 was approximately 2.26%. A 1.0% increase in each of the applicable average interest rates for the six months ended June 30, 2016 would have resulted in an estimated $6.9 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, 2016 at a 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, 2016 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 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.

The Company is the plaintiff in two nearly identical lawsuits against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively "SJGC") pending in United States District Court in Colorado. The Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC has short paid, and continues to short pay, the Company in connection with two long term gas contracts. Under those contracts, SJGC are long term purchasers of some of the Company's natural gas production. Deliveries under the contracts began in October 2011 and the delivery obligation continues through October 2019. SJGC unilaterally breached the contracts claiming 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. Beginning in October 2014, SJGC began short paying the Company based on indexes unilaterally selected by SJGC and not the index specified in the contract. The Company contends that no market disruption event has occurred and that SJGC have breached the contracts by failing to pay the Company based on the express price terms of the contracts. Through June 30, 2016, the Company estimates that it is owed approximately $46 million more than SJGC has paid using the indexes unilaterally selected by them.

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively "WGL") are also involved in a pricing dispute involving contracts that the Company began delivering gas under in January 2016. The Company has invoiced WGL at the index price specified in the contract and WGL has paid the Company based on that invoice price; however, WGL maintains that the index price is no longer appropriate under the contracts and that an undefined alternative index is more appropriate for the delivery point of the gas. The matter has been submitted to arbitration. The Company believes that there is no basis for WGL's position and intends to vigorously dispute the WGL claim in arbitration.

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 condition, results of operations, or cash flows.

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 2015 Form 10-K. The risks described in our 2015 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 2015 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 purchase 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, 2016 - April 30, 2016	182,376	$ 25.69	—	N/A
May 1, 2016 - May 31, 2016	—	$ —	—	N/A
June 1, 2016 - June 30, 2016	—	$ —	—	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 Securities and Exchange Commission (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 U.S. 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, (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 affiliates. 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, 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 one or more SEC-reporting affiliates of SAMIH intends to disclose in its next annual or quarterly SEC report that:

(a) Santander UK plc ("Santander UK") holds two frozen savings accounts and two frozen current accounts for three customers resident in the United Kingdom ("UK") who are currently designated by the United States ("US") under the Specially Designated Global Terrorist ("SDGT") sanctions program. The accounts held by each customer were blocked after the customer's designation and have remained blocked and dormant through the first half of 2016. Revenue generated by Santander UK on these accounts in the first half of 2016 was £7.31 whilst net profits in the first half of 2016 were negligible relative to the overall profits of Banco Santander S.A.

(b) An Iranian national, resident in the UK, who is currently designated by the US under the Iranian Financial Sanctions Regulations ("IFSR") and the Weapons of Mass Destruction Proliferators Sanctions Regulations, held a mortgage with Santander UK that was issued prior to any such designation. The mortgage account was redeemed and closed on April 13, 2016. No further drawdown has been made (or would be allowed) under this mortgage although Santander UK continued to receive repayment instalments prior to redemption. In the first half of 2016, total revenue generated by Santander UK in connection with the mortgage was £434.64 whilst net profits were negligible relative to the overall profits of Banco Santander S.A. 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 held two investment accounts with Santander ISA Managers Limited. The funds within both accounts were invested in the same portfolio fund. The accounts remained frozen until the investments were closed on May 12, 2016 and checks issued to the customer on May 13, 2016. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue in the first half of 2016 generated by Santander UK in connection with the investment accounts was £7.60 whilst net profits in the first half of 2016 were negligible relative to the overall profits of Banco Santander S.A.

(c) A UK national designated by the US under the SDGT sanctions program holds a Santander UK current account. The account remained in arrears through the first half of 2016 (£1,344.01 in debit) and is currently being managed by Santander UK Collections & Recoveries department.

(d) In addition, during the first half of 2016, Santander UK has identified an OFAC match on a power of attorney account. A party listed on the account is currently designated by the US under the SDGT and IFSR sanctions programs. During the first half of 2016, related revenue generated by Santander UK was £129.21 whilst net profits in the first half of 2016 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: August 2, 2016

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).
10.1	Nineteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of April 8, 2016, among Antero Resources Corporation, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 27, 2016).
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, 2016 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, 2016 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: August 2, 2016

/s/ Paul M. Rady

Paul M. Rady
Chief Executive Officer

Exhibit 31.2

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, 2016 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: August 2, 2016

/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, 2016, 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, 2016 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, 2016 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: August 2, 2016

/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, 2016, 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, 2016 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, 2016 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: August 2, 2016

/s/ Glen C. Warren, Jr.

Glen C. Warren, Jr.
Chief Financial Officer