ANTERO RESOURCES Corp
Form 10-Q
August 06, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

OR

o 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. x Yes o 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). x Yes o 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 o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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

The registrant had 262,049,659 shares of common stock outstanding as of August 5, 2014.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q (this 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-loo statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading Item 1A. Risk Factors in this Form 10-Q. These forward-looking statements are based on management s current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy, including the proposed initial public offering of our midstream business;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized 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;
- 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 and conducting our midstream operations;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

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 and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, marketing and transportation risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs, and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2013 (the 2013 Form 10-K) on file with the Securities and Exchange Commission (the SEC) and in Item 1A. Risk Factors of this 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 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.

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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 Form 10-Q.

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PART I FINANCIAL INFORMATION

ANTERO RESOURCES CORPORATION

Condensed Consolidated Balance Sheets

December 31, 2013 and June 30, 2014

(Unaudited)

(In thousands, except share amounts)

		2013	2014
Assets			
Current assets:			
Cash and cash equivalents	$	17,487	19,273
Accounts receivable trade, net of allowance for doubtful accounts of $1,251 in 2013 and 2014		30,610	46,532
Notes receivable - short-term portion		2,667	889
Accrued revenue		96,825	139,553
Derivative instruments		183,000	175,286
Other		2,975	5,695
Total current assets		333,564	387,228
Property and equipment:			
Natural gas properties, at cost (successful efforts method):			
Unproved properties		1,513,136	1,677,642
Proved properties		3,621,672	4,881,002
Fresh water distribution systems		231,684	346,851
Gathering systems and facilities		584,626	873,308
Other property and equipment		15,757	34,019
		5,966,875	7,812,822
Less accumulated depletion, depreciation, and amortization		(407,219)	(601,029)
Property and equipment, net		5,559,656	7,211,793
Derivative instruments		677,780	354,254
Other assets, net		42,581	91,933
Total assets	$	6,613,581	8,045,208

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Balance Sheets

December 31, 2013 and June 30, 2014

(Unaudited)

(In thousands, except share amounts)

		2013	2014
Liabilities and Equity			
Current liabilities:			
Accounts payable	$	370,640	500,774
Accrued liabilities		77,126	116,037
Revenue distributions payable		96,589	154,092
Deferred income tax liability		69,191	71,104
Derivative instruments		646	11,907
Other		8,037	6,800
Total current liabilities		622,229	860,714
Long-term liabilities:			
Long-term debt		2,078,999	3,370,636
Deferred income tax liability		278,580	218,905
Derivative instruments			30,076
Other long-term liabilities		35,113	41,650
Total liabilities		3,014,921	4,521,981
Commitments and contingencies			
Stockholders equity:			
Common stock, $0.01 par value; authorized - 1,000,000,000 shares; issued and outstanding - 262,049,659 shares		2,620	2,620
Preferred stock, $0.01 par value; authorized - 50,000,000 shares; none issued			
Additional paid-in capital		3,402,180	3,463,791
Accumulated earnings		193,860	56,816
Total stockholders equity		3,598,660	3,523,227
Total liabilities and stockholders equity	$	6,613,581	8,045,208

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

Three Months Ended June 30, 2013 and 2014

(Unaudited)

(In thousands, except per share amounts)

		2013	2014
Revenue:			
Natural gas sales	$	172,332	314,151
Natural gas liquids sales		17,244	79,768
Oil sales		2,085	35,633
Gathering, compression, and water distribution			3,565
Marketing			1,987
Commodity derivative fair value gains (losses)		195,483	(123,766)
Total revenue		387,144	311,338
Operating expenses:			
Lease operating		1,454	5,021
Gathering, compression, processing, and transportation		48,670	103,837
Production and ad valorem taxes		10,108	21,358
Marketing			13,946
Exploration		7,300	6,703
Impairment of unproved properties		4,803	1,956
Depletion, depreciation, and amortization		52,589	105,154
Accretion of asset retirement obligations		267	309
General and administrative (including stock compensation expense of $32,474 in 2014)		13,567	58,357
Total operating expenses		138,758	316,641
Operating income (loss)		248,386	(5,303)
Other expenses:			
Interest		(33,468)	(37,260)
Loss on early extinguishment of debt			(20,386)
Total other expenses		(33,468)	(57,646)
Income (loss) from continuing operations before income taxes and discontinued operations		214,918	(62,949)
Provision for income tax (expense) benefit		(83,725)	18,454
Income (loss) from continuing operations		131,193	(44,495)
Discontinued operations:			
Income from sale of discontinued operations, net of income tax expense of $1,354			2,210
Net income (loss) and comprehensive income (loss)	$	131,193	(42,285)
Earnings (loss) per common share:			
Continuing operations	$	0.50	(0.17)
Discontinued operations			0.01
Total	$	0.50	(0.16)
Earnings (loss) per common share - assuming dilution			
Continuing operations	$	0.50	(0.17)
Discontinued operations			0.01
Total	$	0.50	(0.16)

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)

Six Months Ended June 30, 2013 and 2014

(Unaudited)

(In thousands, except per share amounts)

		2013	2014
Revenue:			
Natural gas sales	$	294,278	626,487
Natural gas liquids sales		27,816	153,696
Oil sales		2,962	59,755
Gathering, compression, and water distribution			7,089
Marketing			5,213
Commodity derivative fair value gains (losses)		123,542	(372,695)
Total revenue		448,598	479,545
Operating expenses:			
Lease operating		2,525	9,890
Gathering, compression, processing, and transportation		89,640	187,347
Production and ad valorem taxes		18,727	42,397
Marketing			25,927
Exploration		11,662	13,700
Impairment of unproved properties		6,359	3,353
Depletion, depreciation, and amortization		92,953	196,360
Accretion of asset retirement obligations		531	611
General and administrative (including stock compensation expense of $61,611 in 2014)		26,284	109,342
Total operating expenses		248,681	588,927
Operating income (loss)		199,917	(109,382)
Other expenses:			
Interest		(63,396)	(68,602)
Loss on early extinguishment of debt			(20,386)
Total other expenses		(63,396)	(88,988)
Income (loss) from continuing operations before income taxes and discontinued operations		136,521	(198,370)
Provision for income tax (expense) benefit		(53,325)	59,116
Income (loss) from continuing operations		83,196	(139,254)
Discontinued operations:			
Income from sale of discontinued operations, net of income tax expense of $1,354			2,210
Net income (loss) and comprehensive income (loss)	$	83,196	(137,044)
Earnings (loss) per common share:			
Continuing operations	$	0.32	(0.53)
Discontinued operations			0.01
Total	$	0.32	(0.52)
Earnings (loss) per common share - assuming dilution			
Continuing operations	$	0.32	(0.53)
Discontinued operations			0.01
Total	$	0.32	(0.52)

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Equity

Six Months Ended June 30, 2014

(Unaudited)

(In thousands)

	Common Stock	Additional paid-in capital	Accumulated earnings	Total equity
Balances, December 31, 2013	$ 2,620	3,402,180	193,860	3,598,660
Stock compensation		61,611		61,611
Net loss and comprehensive loss			(137,044)	(137,044)
Balances, June 30, 2014	$ 2,620	3,463,791	56,816	3,523,227

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Condensed Consolidated Statements of Cash Flows

Six Months Ended June 30, 2013 and 2014

(Unaudited)

(In thousands)

		2013	2014
Cash flows from operating activities:			
Net income (loss)	$	83,196	(137,044)
Adjustment to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion		93,484	196,971
Impairment of unproved properties		6,359	3,353
Derivative fair value (gains) losses		(123,542)	372,695
Cash receipts (payments) for settled derivatives		62,277	(118)
Deferred income tax expense (benefit)		53,325	(57,762)
Stock compensation			61,611
Gain on sale of discontinued operations			(3,564)
Loss on early extinguishment of debt			20,386
Other		2,575	969
Changes in assets and liabilities:			
Accounts receivable		(7,935)	(15,922)
Accrued revenue		(19,763)	(42,728)
Other current assets		10,808	(942)
Accounts payable		(1,436)	3,477
Accrued liabilities		20,137	42,475
Revenue distributions payable		8,495	57,503
Other		4,417	(3,331)
Net cash provided by operating activities		192,397	498,029
Cash flows used in investing activities:			
Additions to unproved properties		(271,003)	(239,152)
Drilling and completion costs		(720,910)	(1,103,017)
Additions to fresh water distribution systems		(36,967)	(99,927)
Additions to gathering systems and facilities		(151,737)	(261,667)
Additions to other property and equipment		(1,766)	(11,041)
Change in other assets		3,975	(39,067)
Net cash used in investing activities		(1,178,408)	(1,753,871)
Cash flows from financing activities:			
Issuance of senior notes		231,750	600,000
Repayment of senior notes			(260,000)
Borrowings on bank credit facility, net		743,000	952,000
Payments of deferred financing costs and redemption premiums on early extinguishment of debt		(5,663)	(34,372)
Other		8,802	
Net cash provided by financing activities		977,889	1,257,628
Net (decrease) increase in cash and cash equivalents		(8,122)	1,786
Cash and cash equivalents, beginning of period		18,989	17,487
Cash and cash equivalents, end of period	$	10,867	19,273
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$	62,246	60,031
Supplemental disclosure of noncash investing activities:			

Changes in accounts payable for additions to property and equipment	$	54,051	126,657

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Notes to Condensed Consolidated Financial Statements

December 31, 2013 and June 30, 2014

(Unaudited)

(1) Organization

(a) Business and Organization

Antero Resources Corporation and its consolidated subsidiaries (collectively referred to as the Company, we, or our) are engaged in the exploitation, development, and acquisition of natural gas, natural gas liquids (NGLs) and oil properties in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. We target 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. We also have gathering and compression and fresh water distribution operations in the Appalachian Basin. Our corporate headquarters are in Denver, Colorado.

Our consolidated financial statements include the accounts of Antero Resources Corporation and its subsidiaries, Antero Resources Midstream LLC (Antero Midstream) and Antero Midstream LLC (Midstream Operating).

(b) Corporate Reorganization and Initial Public Offering

Prior to October 16, 2013, the Company s predecessor, Antero Resources LLC, filed reports with the Securities and Exchange Commission. Antero Resources LLC was formed in October 2009 by members of the Company s management team and its sponsor investors. Antero Resources LLC owned 100% of the outstanding shares of Antero Resources Appalachian Corporation, which was formed in March 2008 and renamed Antero Resources Corporation in June 2013. In connection with our initial public offering (IPO) completed on October 16, 2013, all of the ownership interests in Antero Resources LLC were exchanged for similar interests in a newly formed limited liability company, Antero Resources Investment LLC (Antero Investment), and Antero Resources LLC was merged into Antero Resources Corporation. As a result of this reorganization, Antero Investment owned 100% of the issued and outstanding 224,375,000 shares of common stock of Antero Resources Corporation prior to the IPO.

On October 16, 2013, Antero Resources Corporation issued 37,674,659 additional shares of its common stock at $44.00 per share in the IPO, resulting in proceeds to the Company, net of underwriter discounts and expenses of the offering, of approximately $1.6 billion.

In 2013, the Company formed a subsidiary, Antero Midstream. The Company owns all of the common economic interest in Antero Midstream and Antero Investment indirectly owns a special membership interest. In connection with a planned initial public offering of Antero Midstream during 2014, the Company intends to contribute midstream and water assets to Antero Midstream and intends to enter into commercial arrangements for services from Antero Midstream. If the offering is completed, Midstream Operating, which will hold all the midstream and water assets, will be contributed to Antero Midstream. The special membership interest in Antero Midstream provides Antero Investment with certain rights, including the right to cause an initial public offering of Antero Midstream as a master limited partnership (MLP) or similar structure. Following any such initial public offering, the special membership interest will entitle Antero Investment to own the general partner interest in the MLP, which will allow Antero Investment to manage Antero Midstream s business and affairs. Following any such initial public offering, Antero Investment will also indirectly hold the incentive distribution rights in the MLP. We cannot provide any assurance that the proposed initial public offering of the MLP will be completed in a timely fashion, or at all.

(c) Stock Compensation Charge in Connection with the Reorganization

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 our officers and employees. These profits interests provide for the participation in distributions upon liquidation events meeting certain requisite financial return thresholds. In turn, Employee Holdings issued membership interests to certain of our officers and employees. The Employee Holdings interests in Antero Resources LLC were exchanged for similar interests in Antero Investment in connection with the corporate reorganization on October 16, 2013.

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The limited liability company agreement of Antero Investment provides a mechanism that determines how the shares of the Company s common stock will be allocated among the members of Antero Investment, including Employee Holdings, will be determined. 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 interests awards held by Employee Holdings in Antero Investment became probable. Accordingly, we recognized approximately $418 million of stock compensation expense for the vested profits interests through June 30, 2014 and will recognize an additional approximate $69 million over the remaining service period. Stock compensation expense for the profits interests during the three and six months ended June 30, 2014 was $24.1 million and $52.8 million, respectively. Because consideration for the profits interests awards is deemed given by Antero Investment, the charge to stock compensation expense is accounted for as a capital contribution by Antero Investment to the Company and credited to additional paid-in capital.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

These 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, 2013 consolidated financial statements and notes thereto for a more complete understanding of the Company s operations, financial position, and accounting policies. The December 31, 2013 consolidated financial statements have been filed with the SEC in the Company s Annual Report on Form 10-K for the year ended December 31, 2013.

The accompanying unaudited condensed consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States (GAAP) for interim financial information, and, accordingly, do not include all of the information and footnotes required by GAAP for complete consolidated financial statements. In the opinion of management, the accompanying unaudited condensed consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company s financial position as of June 30, 2014, and the results of its operations for the three and six months ended June 30, 2013 and 2014, and its cash flows for the six months ended June 30, 2013 and 2014. The Company has no items of other comprehensive income or loss; therefore, our net loss is identical to our comprehensive loss. All significant intercompany accounts and transactions have been eliminated. Operating results for the period ended June 30, 2014 are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received for natural gas, NGLs, and oil, natural production declines, the uncertainty of exploration and development drilling results, and other factors.

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

Income from discontinued operations for the three and six months ended June 30, 2014 results from the downward adjustment of certain liabilities recorded upon the sale of our Arkoma Basin assets in 2012 because of resolution of such liabilities.

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 an amendment to our senior secured revolving bank credit facility as described in note 3.

(b) Use of Estimates

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

The Company s consolidated financial statements are based on a number of significant estimates including estimates of gas and oil reserve quantities, which are the basis for the calculation of depreciation, depletion, amortization and impairment of oil and gas properties. Reserve estimates by their nature are inherently imprecise.

(c) Risks and Uncertainties

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

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(d) 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.

(e) Derivative Financial Instruments

In order to manage its exposure to oil and gas price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, basis swap agreements, collar agreements, and other similar agreements relating to the price risk associated with a portion of its production. To the extent legal right of offset with a counterparty exists, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position.

The Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives are classified as revenues.

(f) Income Taxes

The Company recognizes deferred tax assets and liabilities for temporary differences resulting from net operating loss carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in the tax laws or tax rates is recognized in income in the period such changes are enacted. Deferred tax assets are reduced by a valuation allowance, when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

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

(g) Fair Value Measurements

FASB ASC 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). The 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 input 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 that are observable for the asset or liability, either directly or indirectly. Instruments which are valued using Level 2 inputs include nonexchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, and interest rate 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.

(h)　Industry Segments and Geographic Information

Management has evaluated how the Company is organized and managed and have identified the following operating segments: (1) the exploration, development, and production of natural gas, NGLs, and oil, (2) gathering and compression, and (3) fresh water distribution.

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All of our assets are located in the United States and all of our revenues are attributable to customers located in the United States.

(i) Marketing Revenues and Expenses

In 2014 the Company began activities to purchase and sell third-party natural gas and to market its excess firm transportation capacity in order to utilize excess firm transportation capacity. Marketing revenues include sales of third-party gas and revenues from the release of firm transportation capacity to others. Marketing expenses include the cost of purchased third-party natural gas. 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 capacity because of alternative delivery points with favorable pricing) is considered unutilized capacity. The costs of unutilized capacity are charged to transportation expense.

(j) Reclassifications

Certain reclassifications have been made to prior periods financial information related to fresh water distribution assets to conform to the 2014 presentation.

(k) Earnings (loss) per share

Because of the losses incurred for both the three and six months ended June 30, 2014, the effect of options and restricted stock awards is antidilutive and loss per share and loss per share-assuming dilution was calculated based on the weighted average number of shares outstanding of 262,049,659. Earnings per common share and earnings per common share assuming dilution for the three and six months ended June 30, 2013 were calculated as if the shares issued in the corporate reorganization and IPO described in note 1 were outstanding as of January 1, 2013.

(3) Long-Term Debt

The Company had long-term debt as follows at December 31, 2013 and June 30, 2014 (in thousands):

		2013	2014
Bank credit facility(a)	$	288,000	1,240,000
7.25% senior notes due 2019(b)		260,000	
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)			600,000
Net unamortized premium		5,999	5,636
	$	2,078,999	3,370,636

(a) Senior Secured Revolving Credit Facility

The Company has a senior secured revolving bank credit facility (the Credit Facility) with a consortium of bank lenders. The maximum amount of the Credit Facility was $3.5 billion at June 30, 2014. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our proved properties and commodity hedge positions and are subject to regular semiannual redeterminations. At June 30, 2014, the borrowing base was $3.0 billion and lender commitments were $2.0 billion. On July 28, 2014, lender commitments were increased to $2.5 billion, including $400 million of commitments under the Midstream Facility described below. Lender commitments can be increased to the full amount of the borrowing base upon approval of the lending group. The maturity date of the Credit Facility is May 5, 2019. The next redetermination of the borrowing base is scheduled to occur in October 2014.

On February 28, 2014, the Company and Midstream Operating entered into a new midstream credit facility (the Midstream Facility) in order to provide for separate borrowings attributable to our midstream business which contains covenants that are substantially identical to those under the Credit Facility. In accordance with the Credit Facility and the Midstream Facility, borrowings under the Midstream Facility reduce availability under the Credit Facility on a dollar-for-dollar basis. The Midstream Facility will mature at the earlier of the closing of the MLP s initial public offering or May 12, 2016. If the MLP s initial public offering is completed, it is expected that the MLP will enter into its own revolving credit facility in connection with the completion thereof.

The Credit Facility and the Midstream Facility are ratably secured by mortgages on substantially all of the Company s properties and guarantees from the Company or its subsidiaries, as applicable. The Credit Facility and the Midstream Facility contain certain covenants, including restrictions on indebtedness and dividends, and, in the case of the Credit Facility, requirements with respect to working capital and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company s election at the time of borrowing. The Company was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2013 and June 30, 2014.

As of June 30, 2014, the Company had a total outstanding balance under the Credit Facility and Midstream Facility of $1.24 billion, with a weighted average interest rate of 2.03%, and outstanding letters of credit of $237 million. As of December 31, 2013, the Company had an outstanding balance under the Credit Facility of $288 million, with a weighted average interest rate of 1.61%, and outstanding letters of credit of $32 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 facility based on utilization.

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(b) 7.25% Senior Notes Due 2019

On May 23, 2014, the Company redeemed the outstanding 7.25% senior notes due 2019 (the 2019 notes) having a principal balance of $260 million at a redemption price of 100% of the principal amount plus a make-whole premium of $17.4 million. The make-whole premium along with the write-off of $3 million of deferred financing costs was charged to Loss on early extinguishment of debt in the accompanying statements of operations. The redemption was financed using a portion of the proceeds from the offering of the Company s 5.125% senior notes due 2022 (the 2022 notes) described below.

(c) 6.00% Senior Notes Due 2020

On November 19, 2012, the Company issued $300 million of 6.00% senior notes due December 1, 2020 (the 2020 notes) at par. On February 4, 2013, the Company issued an additional $225 million of 2020 notes at 103% of par. The 2020 notes are unsecured and effectively subordinated to the Company s Credit Facility and the Midstream Facility to the extent of the value of the collateral securing such facilities. The 2020 notes rank pari passu to our other outstanding senior notes. The 2020 notes are guaranteed on a senior unsecured basis by the Company s existing subsidiaries and certain of its future restricted subsidiaries. Interest on the 2020 notes is payable on June 1 and December 1 of each year. The Company may redeem all or part of the 2020 notes at any time on or after December 1, 2015 at redemption prices ranging from 104.50% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2020 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the 2020 notes, plus accrued interest. At any time prior to December 1, 2015, the Company may redeem the 2020 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2020 notes plus a make-whole premium and accrued interest. If the Company undergoes a change of control, the holders of the 2020 notes will have the right to require the Company 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, the Company issued $1 billion of 5.375% senior notes due November 21, 2021 (the 2021 notes) at par. The 2021 notes are unsecured and effectively subordinated to the Credit Facility and the Midstream Facility to the extent of the value of the collateral securing such facilities. The 2021 notes rank pari passu to our other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several basis by the Company s existing subsidiaries and certain of its future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. The Company 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, the Company 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, the Company 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 the Company undergoes a change of control prior to May 1, 2015, it may redeem all, but not less than all, of the 2021 notes at a redemption price equal to 110% of the principal amount of the 2021 notes. If the Company undergoes a change of control, it 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.

(e) 5.125% Senior Notes Due 2022

On May 6, 2014, the Company issued $600 million of 5.125% senior notes due December 1, 2022 (the 2022 notes) at par. The 2022 notes are unsecured and effectively subordinated to the Credit Facility and the Midstream Facility to the extent of the value of the collateral securing such facilities. The 2022 notes rank pari passu to our other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several basis by the Company s existing subsidiaries and certain of its future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. The Company 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, the Company 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, the Company 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 the Company undergoes a change of control prior to December 1, 2015, it

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may redeem all, but not less than all, of the 2022 notes at a redemption price equal to 110% of the principal amount of the 2022 notes. If the Company undergoes a change of control, the holders of the 2022 notes will have the right to require the Company 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) Treasury Management Facility

The Company has a stand-alone revolving note with a lender under the Credit Facility which provides for up to $25.0 million of cash management obligations in order to facilitate the Company s daily treasury management. Borrowings under the revolving note are secured by the collateral for the revolving credit facility. Borrowings under the facility bear interest at the lender s prime rate plus 1.0%. The note matures on June 1, 2015. At December 31, 2013 and June 30, 2014, there were no outstanding borrowings under this facility.

(4) Asset Retirement Obligations

The following is a reconciliation of the Company s asset retirement obligations for the six months ended June 30, 2014 (in thousands). This amount is included in other long-term liabilities on the accompanying Condensed Consolidated Balance Sheet.

Asset retirement obligations beginning of period	$	11,859
Obligations incurred		618
Accretion expense		611
Asset retirement obligations end of period	$	13,088

(5) Stock-Based Compensation

The Company is authorized to grant up to 16,906,500 stock-based compensation awards to employees and directors of the Company under the Antero Resources Corporation Long-Term Incentive Plan (the Plan). The Plan allows stock-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 the Company s Board of Directors. A total of 14,870,943 shares are available for future grant under the Plan as of June 30, 2014.

Our stock-based compensation expense is as follows for the six months ended June 30, 2014 (in thousands):

Profits interests awards (see note 1)	$	52,768
Restricted stock awards		8,596
Stock options		247
Total expense	$	61,611

Restricted Stock and Restricted Stock Unit Awards

Restricted stock awards vest subject to the satisfaction of service requirements. The grant date fair value of these awards are determined based on the price of the Company s common stock on the date of the grant. A summary of restricted stock and restricted stock unit awards activity during the six months ended June 30, 2014 is as follows:

	Number of shares		Weighted average grant date fair value		Aggregate intrinsic value (in thousands)
Total granted and unvested, December 31, 2013	45,093	$	54.27	$	2,861
Granted	1,923,448	$	65.00		126,236
Vested					
Forfeited	(3,323)	$	58.40		(218)
Total awarded and unvested June 30, 2014	1,965,218	$	64.82	$	128,977

Unamortized expense of $118.6 million at June 30, 2014 is expected to be recognized over approximately 3.5 to 4 years. Intrinsic value is based on the closing price of the Company s stock on the referenced dates.

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Stock Options

Stock options granted under the Plan to date vest over periods from one to four years and have a maximum contractual life of 10 years. We recognize expense related to stock options on a straight-line basis over the requisite service period, less awards expected to be forfeited. Stock options are granted with an exercise price equal to the market price of our common stock on the date of grant. A summary of stock option activity for the six months ended June 30, 2014 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2013	70,339	$ 54.15	9.79	$ 653
Options granted				
Options exercised				
Options cancelled				
Options expired				
Outstanding at June 30, 2014	70,339	$ 54.15	9.29	$ 807
Expected to vest as of June 30, 2014	70,339	$ 54.15	9.29	$ 807
Exercisable at June 30, 2014				

Intrinsic value is based on the closing price of the Company s stock on the referenced dates.

We use a Black-Scholes option-pricing model to determine the fair value of our stock options. Expected volatility was derived from the volatility of the historical stock prices of a peer group of similar publicly traded companies stock prices. The risk-free interest rate was determined using the implied yield currently available for zero-coupon U.S. government issues with a remaining term approximating the expected life of the options. We assumed no dividend yield.

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

Dividend yield	%
Volatility	35%
Risk-free interest rate	1.48%
Expected life (years)	6.17
Weighted average fair value of options granted	$ 20.20

As of June 30, 2014, there was $1.1 million of unrecognized stock-based compensation expense related to nonvested stock options. That expense is expected to be recognized over a weighted average period of 3 years.

(6) Financial Instruments

The carrying values of trade receivables and trade payables at December 31, 2013 and June 30, 2014 approximated market value because of their short-term nature. The carrying value of the bank credit facility at December 31, 2013 and June 30, 2014 approximated fair value because the variable interest rates are reflective of current market conditions.

The fair value of the Company s senior notes was approximately $1.9 billion, based on Level 2 market data inputs at December 31, 2013 and $2.2 billion at June 30, 2014.

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

(7) Derivative Instruments

(a) Commodity Derivatives

The Company periodically enters into oil and natural gas derivative contracts with counterparties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas, 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 recognized upon the ultimate sale of the oil and natural gas produced.

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For the six months ended June 30, 2013 and 2014, the Company was party to natural gas and oil fixed price swaps. When actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price the Company receives the difference from the counterparty. The Company s natural gas and oil swaps have not been designated as hedges for accounting purposes; therefore, all gains and losses were recognized in income currently.

As of June 30, 2014, the Company s fixed price natural gas and oil swaps positions from July 1, 2014 through December 31, 2019 are summarized in the following table.

	Natural gas MMbtu/day	**Oil Bbls/day**		**Weighted average index price**
Three Months ending September 30, 2014:				
TCO	210,000		$	5.01
Dominion South	160,000		$	5.04
NYMEX	340,000		$	4.08
CGTLA	10,000		$	3.82
NYMEX-WTI		3,000	$	94.13
Total	720,000	3,000		
Three Months ending December 31, 2014:				
TCO	210,000		$	5.24
Dominion South	160,000		$	5.27
NYMEX	340,000		$	4.18
CGTLA	10,000		$	3.98
NYMEX-WTI		3,000	$	94.13
Total	720,000	3,000		
Year ending December 31, 2015:				
TCO	120,000		$	5.01
Dominion South	230,000		$	5.60
NYMEX	260,000		$	4.13
CGTLA	40,000		$	4.00
2015 Total	650,000			
Year ending December 31, 2016:				
TCO	60,000		$	4.91
Dominion South	272,500		$	5.35
NYMEX	140,000		$	4.17
CGTLA	170,000		$	4.09
2016 Total	642,500			
Year ending December 31, 2017:				
NYMEX	290,000		$	4.38
CGTLA	420,000		$	4.27
CCG	70,000		$	4.57
2017 Total	780,000			
Year ending December 31, 2018:				
NYMEX	710,000		$	4.60
Year ending December 31, 2019:				
NYMEX	467,500		$	4.41

In addition, the Company has entered into natural gas basis differential positions which settle on the pricing index to basis differential of Columbia Gas (TCO) to the NYMEX Henry Hub natural gas price as follows:

	Natural gas MMbtu/day	Hedged Differential
Year ending December 31, 2015:	390,000	$ (0.35)
Year ending December 31, 2016:	170,000	$ (0.41)
Year ending December 31, 2017:	90,000	$ (0.50)

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(b) Summary

The following is a summary of the fair values of derivative instruments not designated as hedges for accounting purposes and where such values are recorded in the consolidated balance sheets as of December 31, 2013 and June 30, 2014. None of the Company s derivative instruments are designated as hedges for accounting purposes.

	December 31, 2013		June 30, 2014	
	Balance sheet location	Fair value (In thousands)	Balance sheet location	Fair value (In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$ 183,000	Current assets	$ 175,286
Commodity contracts	Long-term assets	677,780	Long-term assets	354,254
Total asset derivatives		860,780		529,540
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	646	Current liabilities	11,907
Commodity contracts	Long-term liabilities		Long-term liabilities	30,076
Total liability derivatives		646		41,983
Net derivatives		$ 860,134		$ 487,557

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the condensed consolidated balance sheets for the periods presented, all at fair value (in thousands):

	December 31, 2013			June 30, 2014		
	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets (liabilities) 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	$ 887,034	(26,254)	860,780	$ 632,885	(103,345)	529,540
Commodity derivative liabilities	$ (646)		(646)	$ (55,818)	13,835	(41,983)

The following is a summary of derivative fair value gains (losses) and where such values are recorded in the consolidated statements of operations for the three and six months ended June 30, 2013 and 2014 (in thousands):

	Statement of operations location		Three months ended June 30 2013	2014	Six months ended June 30 2013	2014
Commodity derivative fair value gains (losses)	Revenue	$	195,483	(123,766)	123,542	(372,695)

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

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(8) Contingencies

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

(9) Segment Information

The operating results and assets of the Company s reportable segments were as follows for the three months ended June 30, 2013 and 2014 (in thousands):

	Exploration and production	**Gathering and compression**	**Fresh water distribution**	**Elimination of intersegment transactions**	**Consolidated total**
2013:					
Revenue:					
Third-party	$ 387,144				387,144
Intersegment		3,539	8,441	(11,980)	
	$ 387,144	3,539	8,441	(11,980)	387,144
Operating income (loss)	$ 250,038	(762)	6,525	(7,415)	248,386
[redacted]					
Capital expenditures for segment assets	$ 516,673	95,762	27,947	(7,652)	632,730

	Exploration and production	**Gathering and compression**	**Fresh water distribution**	**Elimination of intersegment transactions**	**Consolidated total**
2014:					
Revenue:					
Third-party	$ 307,773	2,017	1,548		311,338
Intersegment		14,906	38,970	(53,876)	
	$ 307,773	16,923	40,518	(53,876)	311,338
Operating income (loss)	$ (2,023)	290	23,498	(27,068)	(5,303)
[redacted]					
Capital expenditures for segment assets	$ 817,833	154,144	39,897	(28,776)	983,098

The operating results and assets of the Company s reportable segments were as follows for the six months ended June 30, 2013 and 2014 (in thousands):

	Exploration and	**Gathering and compression**	**Fresh water distribution**	**Elimination of intersegment**	**Consolidated total**

		production			transactions	
2013:						
Revenue:						
Third-party	$	448,598				448,598
Intersegment			5,492	12,806	(18,298)	
	$	448,598	5,492	12,806	(18,298)	448,598
Operating income (loss)	$	203,128	(1,793)	9,696	(11,114)	199,917
[redacted]						
Capital expenditures for segment assets	$	1,005,152	151,737	36,967	(11,473)	1,182,383

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		Exploration and production	Gathering and compression	Fresh water distribution	Elimination of intersegment transactions	Consolidated total
2014:						
Revenue:						
Third-party	$	472,456	2,947	4,142		479,545
Intersegment			25,749	61,135	(86,884)	
	$	472,456	28,696	65,277	(86,884)	479,545
Operating income (loss)	$	(106,403)	1,239	38,115	(42,333)	(109,382)
Segment assets	$	7,641,668	898,269	348,629	(843,358)	8,045,208
Capital expenditures for segment assets	$	1,399,877	261,667	99,927	(46,667)	1,714,804

(10) Subsidiary Guarantors

The Company s wholly owned subsidiaries each have fully and unconditionally guaranteed the Company s outstanding senior notes. The following Condensed Consolidating Balance Sheets as of December 31, 2013 and June 30, 2014 present financial information for Antero Resources Corporation as the Parent on a stand-alone basis (carrying its investment in subsidiaries using the equity method), combined financial information for the subsidiary guarantors (Antero Resources Midstream LLC and Antero Midstream LLC) as a group, and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. The guarantor subsidiaries had no revenues, expenses, or cash flow during the year ended December 31, 2013 or the three and six months ended June 30, 2014. The guarantor subsidiaries are not restricted from making distributions to the Company.

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Condensed Consolidating Balance Sheets

December 31, 2013

(In thousands)

	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
Assets				
Current assets:				
Cash and cash equivalents	$ 17,487			17,487
Other	316,077	1	(1)	316,077
Total current assets	333,564	1	(1)	333,564
Property and equipment, net	5,559,656			5,559,656
Other long-term assets	720,361			720,361
Investment in subsidiary	1		(1)	
	$ 6,613,582	1	(2)	6,613,581
Liabilities and Stockholders Equity				
Current liabilities	$ 622,229			622,229
Long-term debt	2,078,999			2,078,999
Other long-term liabilities	313,693			313,693
Due to subsidiary	1		(1)	
Total liabilities	3,014,922		(1)	3,014,921
Stockholders equity	3,598,660	1	(1)	3,598,660
Total liabilities and equity	$ 6,613,582	1	(2)	6,613,581

June 30, 2014

(In thousands)

	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
Assets				
Current assets:				
Cash and cash equivalents	$ 19,273			19,273
Other	367,955	1	(1)	367,955
Total current assets	387,228	1	(1)	387,228
Property and equipment, net	7,211,793			7,211,793

Other long-term assets		446,187			446,187
Investment in subsidiary		1		(1)	
	$	8,045,209	1	(2)	8,045,208
Liabilities and Stockholders Equity					
Current liabilities	$	860,714			860,714
Long-term debt		3,370,636			3,370,636
Other long-term liabilities		290,631			290,631
Due to subsidiary		1		(1)	
Total liabilities		4,521,982		(1)	4,521,981
Stockholders equity		3,523,227	1	(1)	3,523,227
Total liabilities and equity	$	8,045,209	1	(2)	8,045,208

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

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

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

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of June 30, 2014, we held approximately 486,000 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.

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.

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, 2014, our estimated proved reserves were approximately 9.1 Tcfe, consisting of 7.9 Tcf of natural gas, 186 MMBbl of NGLs, and 16 MMBbl of oil. This represents a 19% increase from proved reserve volumes at December 31, 2013. These reserve estimates have been prepared by our internal reserve engineers and management without review by our independent reserve engineers. As of June 30, 2014, we had approximately 5,400 potential horizontal well locations on our existing leasehold acreage, both proven and unproven.

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

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

Address, Internet Website and Availability of Public Filings

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

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

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

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2014 Developments and Highlights

Production and Financial Results

For the three months ended June 30, 2014, we generated cash flow from operations of $224 million, a net loss from continuing operations of $44 million, and Adjusted EBITDAX of $266 million. The net loss from continuing operations of $44 million for the three months ended June 30, 2014 included $124 million of net commodity derivative losses, of which $1 million related to cash settled derivative gains, a $20 million loss on the early extinguishment of debt, a deferred tax benefit of $18 million, and stock compensation expense of $32 million. This compares to cash flow from operations of $82 million, net income of $131 million, and Adjusted EBITDAX of $133 million for the three months ended June 30, 2013. See Non-GAAP Financial Measure for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

For the six months ended June 30, 2014, we generated cash flow from operations of $498 million, a net loss from continuing operations of $139 million, and Adjusted EBITDAX of $540 million. The net loss from continuing operations of $139 million for the six months ended June 30, 2014 included $373 million of commodity derivative losses, a $20 million loss on the early extinguishment of debt, a deferred tax benefit of $59 million, and stock compensation expense of $62 million. This compares to cash flow from operations of $192 million, net income of $83 million, and Adjusted EBITDAX of $251 million for the six months ended June 30, 2013. See Non-GAAP Financial Measure for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

For the three months ended June 30, 2014, our production totaled approximately 81 Bcfe, or 891 MMcfe per day, a 94% increase compared to 42 Bcfe, or 458 MMcfe per day for the three months ended June 30, 2013. The average price received for production for the three months ended June 30, 2014 was $5.30 per Mcfe before the effects of cash settled commodity hedges compared to $4.60 per Mcfe for the three months ended June 30, 2013. Average prices after the effects of cash settled commodity hedges were $5.31 per Mcfe for the three months ended June 30, 2014 compared to $4.94 for the three months ended June 30, 2013.

For the six months ended June 30, 2014, our production totaled approximately 152 Bcfe, or 838 MMcfe per day, a 99% increase compared to 76 Bcfe, or 421 MMcfe per day for the six months ended June 30, 2013. The average price received for production for the six months ended June 30, 2014 was $5.54 per Mcfe before the effects of cash settled commodity hedges compared to $4.27 per Mcfe for the six months ended June 30, 2013. Average prices after the effects of cash settled commodity hedges were $5.53 per Mcfe for the six months ended June 30, 2014 compared to $5.09 for the six months ended June 30, 2013.

Proved Reserves

As of June 30, 2014, our estimated proved reserves were 9.1 Tcfe, consisting of 7.9 Tcf of natural gas, 186 MMBbls of NGLs, and 16 MMBbls of oil. This represents a 19% increase from proved reserve volumes at December 31, 2013 as a result of our successful ongoing drilling and development program. The percentage of proved reserves classified as proved developed increased to 30% at June 30, 2014 compared to 27% at December 31, 2013. Proved reserves at both dates were prepared assuming ethane rejection. Estimates of proved reserves at June 30, 2014 were prepared by our internal reserve engineers and management without review by our independent reserve engineers. Our December 31, 2013 proved reserves were audited by independent reserve engineers.

2014 Capital Budget

For the six months ended June 30, 2014, our total capital expenditures were approximately $1.7 billion, including drilling and completion costs of $1.1 billion, gathering and compression costs of $262 million, fresh water distribution project costs of $100 million, leasehold acquisition costs of $ 239 million (including approximately $95 million for an acquisition transaction of 6,363 Utica acres), and other capital expenditures of $11 million. Our capital expenditure budget for 2014 is $2.85 billion and includes: $1.8 billion for drilling and completion; $750 million for the expansion of midstream facilities, including $200 million for fresh water distribution infrastructure; and $300 million for core leasehold acreage acquisitions. We do not budget for producing property acquisitions. Substantially all of the $1.8 billion allocated for drilling and completion is allocated to our operated drilling in rich gas areas. Approximately 75% of our drilling and completion budget is allocated to the Marcellus Shale, and the remaining 25% is allocated to the Utica Shale. Our 2014 capital budget assumes a drilling and completion program that averages 18 rigs during the year, and we are currently reviewing the capital budget for 2014. We are monitoring the construction of additional third party midstream capacity, including processing, and expect to provide updated production and capital guidance during the third quarter of 2014. Additionally, we periodically review capital expenditures and adjust the budget based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Credit Facility Amendment

On July 28, 2014, our revolving credit facility was amended to increase lender commitments from $2.0 billion to $2.5 billion, including $400 million of commitments under the midstream credit facility. The letter of credit sublimit was increased from $500 million to $650 million. Maximum borrowings under the facility are $3.5 billion and the current borrowing base is $3.0 billion. Lender commitments can be increased to the full $3.0 billion upon the approval of the lenders. The maturity date of the facility is

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May 5, 2019. The borrowing base under the Credit Facility is redetermined semiannually and is based on the lenders judgment of the volume of our proved oil and gas reserves and the estimated future cash flows from these reserves and the value of our hedge positions. The next redetermination is scheduled to occur in October 2014.

At June 30, 2014, we had $1.24 billion of borrowings and $237 million of letters of credit outstanding under the Credit Facility and $523 million of available borrowing capacity, based on $2.0 billion of lender commitments at that date.

Issuance of 5.125% Notes due 2022

In May 2014, we issued $600 million of 5.125% senior notes due December 1, 2022. The proceeds of the notes were used to retire the remaining $260 million principal amount of our 7.25% notes due 2019 and for general corporate purposes, including paying down amounts outstanding under our revolving credit facility and funding our drilling and development program. We incurred a loss on early extinguishment of debt of $20 million on the retirement of the 7.25% notes. Our outstanding senior notes totaling $2.125 billion now have interest rates ranging from 5.125% to 6.00% and have due dates ranging from December 1, 2020 to December 1, 2022.

Hedge Position

As of June 30, 2014, we had entered into hedging contracts for July 1, 2014 through December 31, 2019 for 1.32 Tcf of our projected natural gas production at a weighted average index price of $4.58 per MMbtu and 552,000 Bbls of oil at a weighted average price of $94.13 per Bbl. These hedging contracts include contracts for the year ended December 31, 2014 of approximately 132 Bcf of natural gas at a weighted average index price of $4.65 per Mcf and 552,000 Bbls of oil at $94.13 per Bbl.

In addition, we had entered into natural gas basis differential positions for 2015 through 2017 for 237 Bcf at a weighted average index price of $(0.39) which settle on the pricing index to basis differential of Columbia Gas (TCO) to the NYMEX Henry Hub natural gas price.

Pending Midstream MLP IPO

On February 7, 2014, our subsidiary, Antero Resources Midstream LLC filed a Registration Statement on Form S-1 with the SEC relating to an initial public offering of common units representing limited partner interests. If the offering is closed, Antero Resources Midstream LLC will convert from a limited liability company into a Delaware master limited partnership and we intend to contribute midstream assets to the MLP as well as the right to develop additional midstream infrastructure to service our growing production. The proposed offering has not yet commenced, in part, because we have not yet received the required Internal Revenue Service (the IRS) ruling due to the temporary suspension of such rulings with respect to qualifying income by the IRS. However, we cannot provide any assurance that we will be able to complete the proposed initial public offering of the MLP in a timely fashion, or at all.

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Results of Operations

Three months ended June 30, 2013 Compared to Three months ended June 30, 2014

The following table sets forth selected operating data for the three months ended June 30, 2013 compared to the three months ended June 30, 2014:

	Three Months Ended June 30, 2013	2014	Amount of Increase (Decrease)	Percent Change
	(in thousands, except per unit and production data)			
Operating revenues:				
Natural gas sales	$ 172,332	314,151	141,819	82%
NGL sales	17,244	79,768	62,524	363%
Oil sales	2,085	35,633	33,548	1,609%
Gathering, compression, and water distribution		3,565	3,565	*
Marketing		1,987	1,987	*
Commodity derivative fair value gains (losses)	195,483	(123,766)	(319,249)	*
Total operating revenues	387,144	311,338	(75,806)	(20)%
Operating expenses:				
Lease operating	1,454	5,021	3,567	245%
Gathering, compression, processing, and transportation	48,670	103,837	55,167	113%
Production and ad valorem taxes	10,108	21,358	11,250	111%
Marketing		13,946	13,946	*
Exploration	7,300	6,703	(597)	(8)%
Impairment of unproved properties	4,803	1,956	(2,847)	(59)%
Depletion, depreciation, and amortization	52,589	105,154	52,565	100%
Accretion of asset retirement obligations	267	309	42	16%
General and administrative (before stock compensation expense)	13,567	25,883	12,316	91%
Stock compensation		32,474	32,474	*
Total operating expenses	138,758	316,641	177,883	128%
Operating income (loss)	248,386	(5,303)	(253,689)	*
Other Expenses:				
Interest expense	(33,468)	(37,260)	(3,792)	11%
Loss on early extinguishment of debt		(20,386)	(20,386)	*
Total other expenses	(33,468)	(57,646)	(24,178)	72%
Income (loss) before income taxes and discontinued operations	214,918	(62,949)	(277,867)	*
Income tax (expense) benefit	(83,725)	18,454	102,179	*
Income (loss) from continuing operations	131,193	(44,495)	(175,688)	*
Income from discontinued operations		2,210	2,210	*
Net income (loss)	$ 131,193	(42,285)	(173,478)	*
Adjusted EBITDAX (1)	$ 132,608	266,462	133,854	101%

Production data:							
Natural gas (Bcf)		39		70		31	78%
NGLs (MBbl)		354		1,451		1,097	310%
Oil (MBbl)		25		391		366	1,495%
Combined (Bcfe)		42		81		39	94%
Daily combined production (MMcfe/d)		458		891		433	94%
Average prices before effects of hedges(2):							
Natural gas (per Mcf)	$	4.37	$	4.49	$	0.12	3%
NGLs (per Bbl)	$	48.70	$	54.98	$	6.28	13%
Oil (per Bbl)	$	85.07	$	91.20	$	6.13	7%
Combined (per Mcfe)	$	4.60	$	5.30	$	0.70	15%
Average realized prices after effects of hedges(2):							
Natural gas (per Mcf)	$	4.74	$	4.52	$	(0.22)	(5)%
NGLs (per Bbl)	$	48.70	$	54.98	$	6.28	13%
Oil (per Bbl)	$	80.70	$	87.31	$	6.61	8%
Combined (per Mcfe)	$	4.94	$	5.31	$	0.37	8%
Average Costs (per Mcfe):							
Lease operating	$	0.03	$	0.06	$	0.03	107%
Gathering, compression, processing, and transportation	$	1.17	$	1.28	$	0.11	10%
Production and advalorem taxes	$	0.24	$	0.26	$	0.02	10%
Depletion, depreciation, amortization, and accretion	$	1.27	$	1.30	$	0.03	2%
General and administrative (before stock compensation expense)	$	0.33	$	0.32	$	(0.01)	(3)%

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(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).

(2) Average sales prices shown in the table reflect both of the before and after effects of our cash settled derivatives. Our calculation of such after effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGL 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.

* Not meaningful or applicable

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $192 million for the three months ended June 30, 2013 to $430 million for the three months ended June 30, 2014, an increase of $238 million, or 124%. Our production increased by 94% over that same period, from 42 Bcfe, or 458 MMcfe per day, for the three months ended June 30, 2013 to 81 Bcfe, or 891 MMcfe per day, for the three months ended June 30, 2014. Net equivalent prices before the effects of realized hedge gains increased from $4.60 per Mcfe for the three months ended June 30, 2013 to $5.30 for the three months ended June 30, 2014, an increase of 15%. The 15% increase in net equivalent prices for the three months ended June 30, 2014 compared to the prior year quarter resulted from a 3% increase in natural gas prices; the remaining 12% increase resulted from an increase in the mix of production of NGLs and oil compared to the prior year period and increased prices for NGLs and oil. Increased production volumes accounted for an approximate $181 million increase in year-over year revenues (calculated as the change in year-to-year volumes times the prior year average price), and commodity price increases accounted for an approximate $57 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from additional producing wells as a result of our ongoing drilling program.

Commodity derivative fair value losses. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our results of operations. For the three months ended June 30, 2013 and 2014, our hedges resulted in derivative fair value gains (losses) of $195 million and $(124) million, respectively. The derivative fair value losses included $14 million and $1 million of cash settlements received on derivatives for the three months ended June 30, 2013 and 2014, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. Derivative asset or liability positions at the end of any accounting period may reverse to the extent natural gas and oil strip prices increase or decrease from their levels at the end of the accounting period or as gains or losses are realized through settlement. We expect continued volatility in commodity prices and the related fair value of our derivative instruments.

Gathering, compression, and water distribution. Beginning in the fourth quarter of 2013, we began to recognize our midstream gathering, compression, and water distribution operations as reportable segments. Gathering, compression, and water distribution fees of $3.6 million during the three months ended June 30, 2014 represent the portion of such fees that are charged to outside working interest owners and other third parties. Such fees were immaterial in the prior year period and were netted against gathering expenses and capital expenditures.

Marketing. In 2014, we have begun activities to purchase and sell third-party natural gas and market our excess firm transportation capacity in order to utilize our excess firm transportation capacity. Marketing revenues of $2 million and expenses of $14 million for the three months ended June 30, 2014 relate to these activities. Marketing costs include firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize the capacity. This includes firm transportation costs of $11 million related to an ethane transportation contract which is not being utilized because we are not currently recovering ethane. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.

Lease operating expenses. Lease operating expenses increased by 245% from the three months ended June 30, 2013 to the three months ended June 30, 2014 from $1.5 million to $5.0 million. The increase occurred because of the increase in the number of producing wells. On a per unit basis, lease operating expenses increased from $0.03 per Mcfe for the three months ended

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June 30, 2013 to $0.06 for the three months ended June 30, 2014. Lease operating expenses per unit have increased as an increased proportion of wells have been on production for longer periods of time compared to the prior year period. Lease operating expenses are expected to increase on a per unit basis as properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $49 million for the three months ended June 30, 2013 to $104 million for the three months ended June 30, 2014. The increase in these expenses resulted from the increase in production, firm transportation commitments, and third-party gathering and compression expenses. On a per-Mcfe basis, total gathering, compression, processing and transportation expenses increased from $1.17 per Mcfe for the three months ended June 30, 2013 to $1.28 for the three months ended June 30, 2014 as a larger proportion of our gas was processed compared to the prior year period.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $10 million for the three months ended June 30, 2013 to $21 million for the three months ended June 30, 2014, primarily as a result of increased production and midstream assets subject to ad valorem taxes. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally drilled wells could increase our future production tax rates, if such legislation is enacted.

Exploration expense. Exploration expense of $7.3 million for the three months ended June 30, 2013 decreased slightly to $6.7 million for the three months ended June 30, 2014.

Impairment of unproved properties. Impairment of unproved properties was approximately $4.8 million for the three months ended June 30, 2013 compared to $2.0 million for the three months ended June 30, 2014. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

DD&A. DD&A increased from $53 million for three months ended June 30, 2013 to $105 million for the three months ended June 30, 2014, primarily because of increased production. DD&A per Mcfe increased by 2% from $1.27 per Mcfe during the three months ended June 30, 2013 to $1.30 per Mcfe during the three months ended June 30, 2014, primarily as a result of increased depreciation on midstream assets and facilities.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property s carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the three months ended June 30, 2013 or 2014 for proved properties.

General and administrative and stock compensation expense. General and administrative expense (before stock compensation expense) increased from $14 million for the three months ended June 30, 2013 to $26 million for the three months ended June 30, 2014, primarily as a result of increased staffing levels and related salary and benefits expenses and increases in legal and other general corporate expenses, all of which resulted from our growth in development activities and production levels. On a per unit basis, general and administrative expense before stock compensation decreased by 3%, from $0.33 per Mcfe during the three months ended June 30, 2013 to $0.32 per Mcfe during the three months ended June 30, 2014, primarily due to a 94% increase in production. We had 184 employees as of June 30, 2013 and 330 employees as of June 30, 2014.

Noncash stock compensation expense of $32 million included a charge of $24 million for the recognition and amortization of expense related to vested profits interests upon the completion of the IPO in 2013. See note 1 to the consolidated financial statements included elsewhere in this report for more information on the vested profits interest charge.

Interest expense. Interest expense increased from $33 million for the three months ended June 30, 2013 to $37 million for the three months ended June 30, 2014, primarily due to increased indebtedness. Interest expense includes approximately $2 million of non-cash amortization of deferred financing costs for each of the three months ended June 30, 2013 and 2014.

Loss on early extinguishment of debt. On May 23, 2014, we redeemed the outstanding 7.25% senior notes due 2019 having a principal balance of $260 million at a redemption price of 100% of the principal amount plus a make-whole premium of $17.4 million. The make-whole premium along with the write-off of $3 million of deferred financing costs was charged to Loss on early extinguishment of debt in the accompanying statements of operations. The redemption was financed using a portion of the proceeds from the offering of our 2022 notes.

Income tax benefit (expense). Income tax benefit (expense) changed from a deferred tax expense of $84 million for the three months ended June 30, 2013 to a deferred tax benefit of $18 million for the three months ended June 30, 2014. The deferred tax benefit in 2014 results from the loss incurred for financial reporting purposes in the three months ended June 30, 2014 resulting in a decrease in deferred tax liabilities. Stock compensation expense of $24 million related to the vested profits interest charge is not deductible for federal or state income taxes and, along with the effect of state taxes, largely accounts for the difference between the federal tax rate of 35% and the rate at which the income tax benefit was provided for the three months ended June 30, 2014.

At December 31, 2013, we had approximately $1.2 billion of U.S. federal net operating loss carryforwards (NOLs) and approximately $1.1 billion of state NOLs, which expire starting in 2024 and through 2033. 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 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 it believes 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, 2014 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, 2014, we have accrued approximately $0.8 million of interest on unrecognized tax benefits.

The Internal Revenue Service recently completed its examination of the tax returns of Antero Resources Finance Corporation (which was merged with Antero Resources Corporation in December 2013) for its tax years 2011 and 2012. There are no adjustments to our tax returns as a result of the examination.

Income from discontinued operations. On June 29, 2012, we completed the sale of our Arkoma Basin assets in Oklahoma and recorded a loss in connection with the sale. The loss on the sale of the Arkoma Basin assets was adjusted downward by $3.6 million (before tax expense of $1.4 million) for the three months ended June 30, 2014 as a result of the resolution of certain liabilities recorded at the time of the sale.

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Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2014

The following table sets forth selected operating data for the six months ended June 30, 2013 compared to the six months ended June 30, 2014:

	Six Months Ended June 30, 2013	2014	Amount of Increase (Decrease)	Percent Change
	(in thousands, except per unit and production data)			
Operating revenues:				
Natural gas sales	$ 294,278	626,487	332,209	113%
NGL sales	27,816	153,696	125,880	453%
Oil sales	2,962	59,755	56,793	1,917%
Gathering, compression, and water distribution		7,089	7,089	*
Marketing		5,213	5,213	*
Commodity derivative fair value gains (losses)	123,542	(372,695)	(496,237)	*
Total operating revenues	448,598	479,545	30,947	7%
Operating expenses:				
Lease operating	2,525	9,890	7,365	292%
Gathering, compression, processing, and transportation	89,640	187,347	97,707	109%
Production and ad valorem taxes	18,727	42,397	23,670	126%
Marketing		25,927	25,927	*
Exploration	11,662	13,700	2,038	17%
Impairment of unproved properties	6,359	3,353	(3,006)	(47)%
Depletion, depreciation, and amortization	92,953	196,360	103,407	111%
Accretion of asset retirement obligations	531	611	80	15%
General and administrative (before stock compensation expense)	26,284	47,731	21,447	82%
Stock compensation		61,611	61,611	*
Total operating expenses	248,681	588,927	340,246	137%
Operating income (loss)	199,917	(109,382)	(309,299)	*
Other Expenses:				
Interest expense	(63,396)	(68,602)	(5,206)	11%
Loss on early extinguishment of debt		(20,386)	(20,386)	*
Total other expenses	(63,396)	(88,988)	(25,592)	72%
Income (loss) before income taxes and discontinued operation	136,521	(198,370)	(334,891)	*
Income tax (expense) benefit	(53,325)	59,116	112,441	*
Income (loss) from continuing operations	83,196	(139,254)	(222,450)	*
Income from discontinued operations		2,210	2,210	*
Net income (loss)	$ 83,196	(137,044)	(220,240)	*
Adjusted EBITDAX (1)	$ 251,357	540,118	288,761	115%
Production data:				
Natural gas (Bcf)	73	132	59	82%
NGLs (MBbl)	559	2,649	2,090	374%
Oil (MBbl)	35	662	627	1,792%
Combined (Bcfe)	76	152	76	99%

Daily combined production (MMcfe/d)		421		838		417	99%
Average prices before effects of hedges(2):							
Natural gas (per Mcf)	$	4.05	$	4.75	$	0.70	17%
NGLs (per Bbl)	$	49.75	$	58.01	$	8.26	17%
Oil (per Bbl)	$	85.36	$	90.24	$	4.88	6%
Combined (per Mcfe)	$	4.27	$	5.54	$	1.27	30%
Average realized prices after effects of hedges(2):							
Natural gas (per Mcf)	$	4.91	$	4.76	$	(0.15)	(3)%
NGLs (per Bbl)	$	49.75	$	58.01	$	8.26	17%
Oil (per Bbl)	$	79.14	$	88.73	$	9.59	12%
Combined (per Mcfe)	$	5.09	$	5.53	$	0.44	9%
Average Costs (per Mcfe):							
Lease operating	$	0.03	$	0.07	$	0.04	117%
Gathering, compression, processing, and transportation	$	1.18	$	1.23	$	0.05	5%
Production and advalorem taxes	$	0.25	$	0.28	$	0.03	12%
Depletion, depreciation, amortization, and accretion	$	1.23	$	1.30	$	0.07	6%
General and administrative (before stock compensation expense)	$	0.35	$	0.31	$	(0.04)	(10)%

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(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).

(2) Average sales prices shown in the table reflect both of the before and after effects of our cash settled derivatives. Our calculation of such after effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGL 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.

* Not meaningful or applicable

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $325 million for the six months ended June 30, 2013 to $840 million for the six months ended June 30, 2014, an increase of $515 million, or 158%. Our production increased by 99% over that same period, from 76 Bcfe, or 421 MMcfe per day, for the six months ended June 30, 2013 to 152 Bcfe, or 838 MMcfe per day, for the six months ended June 30, 2014. Net equivalent prices before the effects of realized hedge gains increased from $4.27 per Mcfe for the six months ended June 30, 2013 to $5.54 for the six months ended June 30, 2014, an increase of 30%. The 30% increase in net equivalent prices for the six months ended June 30, 2014 compared to the prior year period resulted from a 17% increase in natural gas prices; the remaining 13% increase resulted from an increase in the mix of production of NGLs and oil compared to the prior year period and increased prices for NGLs and oil. Increased production volumes accounted for an approximate $323 million increase in year-over year revenues (calculated as the change in year-to-year volumes times the prior year average price), and commodity price increases accounted for an approximate $192 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from additional producing wells as a result of our ongoing drilling program.

Commodity derivative fair value losses. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our results of operations. For the six months ended June 30, 2013 and 2014, our hedges resulted in derivative fair value gains (losses) of $124 million and $(373) million, respectively. The derivative fair value losses included $62 million and $(0.1) million of cash settlements received (paid) on derivatives for the six months ended June 30, 2013 and 2014, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. Derivative asset or liability positions at the end of any accounting period may reverse to the extent natural gas and oil strip prices increase or decrease from their levels at the end of the accounting period or as gains or losses are realized through settlement. We expect continued volatility in commodity prices and the related fair value of our derivative instruments.

Gathering, compression, and water distribution. Beginning in the fourth quarter of 2013, we began to recognize our midstream gathering, compression, and water distribution operations as reportable segments. Gathering, compression, and water distribution fees of $7 million during the six months ended June 30, 2014 represent the portion of such fees that are charged to outside working interest owners and other third parties. Such fees were immaterial in the prior year period and were netted against gathering expenses and capital expenditures.

Marketing. In 2014, we have begun activities to purchase and sell third-party natural gas and our excess firm transportation capacity in order to utilize our excess firm transportation capacity. Marketing revenues of $5 million and expenses of $26 million for the six months ended June 30, 2014 relate to these activities. Marketing costs include firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize the capacity. This includes firm transportation costs of $22 million related to an ethane transportation contract which is not being utilized because we are not currently recovering ethane. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.

Lease operating expenses. Lease operating expenses increased by 292% from the six months ended June 30, 2013 to the six months ended June 30, 2014 from $2.5 million to $9.9 million. The increase occurred because of the increase in the number of producing wells. On a per unit basis, lease operating expenses increased by 117%, from $0.03 per Mcfe for the six months ended June 30, 2013 to $0.07 for the six months ended June 30, 2014. Lease operating expenses per unit have increased as an increased proportion of wells have been on production for longer periods of time compared to the prior year period. Lease operating expenses are expected to increase on a per unit basis as properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $90 million for the six months ended June 30, 2013 to $187 million for the six months ended June 30, 2014. The increase in these expenses resulted from the increase in production, firm transportation commitments, and third-party gathering and compression expenses. On a per-Mcfe basis, total gathering, compression, processing and transportation expenses increased from $1.18 per Mcfe for the six months ended June 30, 2013 to $1.23 for the six months ended June 30, 2014 as a larger proportion of our gas was processed compared to the prior year period.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $19 million for the six months ended June 30, 2013 to $42 million for the six months ended June 30, 2014, primarily as a result of increased production and midstream assets subject to ad valorem taxes. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally drilled wells could increase our future production tax rates, if such legislation is enacted.

Exploration expense. Exploration expense increased from $12 million for the six months ended June 30, 2013 to $14 million for the six months ended June 30, 2014 primarily because of an increase in the cost of unsuccessful lease acquisition efforts due to an increase in lease acquisition efforts.

Impairment of unproved properties. Impairment of unproved properties was approximately $6 million for the six months ended June 30, 2013 compared to $3 million for the six months ended June 30, 2014. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

DD&A. DD&A increased from $93 million for six months ended June 30, 2013 to $196 million for the six months ended June 30, 2014, primarily because of increased production. DD&A per Mcfe increased by 6% from $1.23 per Mcfe during the six months ended June 30, 2013 to $1.30 per Mcfe during the six months ended June 30, 2014, primarily as a result of increased depreciation on midstream assets and facilities.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property s carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the six months ended June 30, 2013 or 2014 for proved properties.

General and administrative and stock compensation expense. General and administrative expense (before stock compensation expense) increased from $26 million for the six months ended June 30, 2013 to $48 million for the six months ended June 30, 2014, primarily as a result of increased staffing levels and related salary and benefits expenses and increases in legal and other general corporate expenses, all of which resulted from our growth in development activities and production levels. On a per unit basis, general and administrative expense before stock compensation decreased by 10%, from $0.35 per Mcfe during the six months ended June 30, 2013 to $0.31 per Mcfe during the six months ended June 30, 2014, primarily due to a 99% increase in production. We had 184 employees as of June 30, 2013 and 330 employees as of June 30, 2014.

Noncash stock compensation expense of $62 million included a charge of $53 million for the recognition and amortization of expense related to vested profits interests upon the completion of the IPO in 2013. See note 1 to the consolidated financial statements included elsewhere in this report for more information on the vested profits interest charge.

Interest expense. Interest expense increased from $63 million for the six months ended June 30, 2013 to $69 million for the six months ended June 30, 2014, primarily due to increased indebtedness. Interest expense includes approximately $3 million and $4 million of non-cash amortization of deferred financing costs for the six months ended June 30, 2013 and 2014, respectively.

Loss on early extinguishment of debt. On May 23, 2014, we redeemed the outstanding 7.25% senior notes due 2019 having a principal balance of $260 million at a redemption price of 100% of the principal amount plus a make-whole premium of $17.4 million. The make-whole premium along with the write-off of $3 million of deferred financing costs was charged to Loss on early extinguishment of debt in the accompanying statements of operations. The redemption was financed using a portion of the proceeds from the offering of our 2022 notes.

Income tax benefit (expense). Income tax benefit (expense) changed from a deferred tax expense of $53 million for the six months ended June 30, 2013 to a deferred tax benefit of $59 million for the six months ended June 30, 2014. The deferred tax benefit in 2014 results from the loss incurred for financial reporting purposes in

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the six months ended June 30, 2014 resulting in a decrease in deferred tax liabilities. Stock compensation expense of $53 million related to the vested profits interest charge is not deductible for federal or state income taxes and, along with the effect of state taxes, largely accounts for the difference between the federal tax rate of 35% and the rate at which the income tax benefit was provided for the six months ended June 30, 2014.

At December 31, 2013, we had approximately $1.2 billion of U.S. federal net operating loss carryforwards (NOLs) and approximately $1.1 billion of state NOLs, which expire starting in 2024 and through 2033. 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 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 it believes 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, 2014 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, 2014, we have accrued approximately $0.8 million of interest on unrecognized tax benefits.

The Internal Revenue Service recently completed its examination of the tax returns of Antero Resources Finance Corporation (which was merged with Antero Resources Corporation in December 2013) for its tax years 2011 and 2012. There are no adjustments to our tax returns as a result of the examination.

Income from discontinued operations. On June 29, 2012, we completed the sale of our Arkoma Basin assets in Oklahoma and recorded a loss in connection with the sale. The loss on the sale of the Arkoma Basin assets was adjusted downward by $3.6 million (before tax expense of $1.4 million) for the six months ended June 30, 2014 as a result of the resolution of certain liabilities recorded at the time of the sale.

Capital Resources and Liquidity

Our primary sources of liquidity have been proceeds from issuances of equity securities and senior notes, borrowings under our revolving credit facilities, asset sales, and net cash provided by operating activities. Our primary use of cash has been for the exploration, development and acquisition of unconventional natural gas and oil properties. 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 expenditures, and liquidity requirements. Our future success in growing 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 should 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.

The following table summarizes our cash flows for the six months ended June 30, 2013 and 2014:

		Six Months Ended June 30, 2013	2014
		(in thousands)	
Net cash provided by operating activities	$	192,397	498,029
Net cash used in investing activities		(1,178,408)	(1,753,871)
Net cash provided by financing activities		977,889	1,257,628
Net (decrease) increase in cash and cash equivalents	$	(8,122)	1,786

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $192 million and $498 million for the six months ended June 30, 2013 and 2014, respectively. The increase in cash flow from operations from the six months ended June 30, 2013 compared to the six months ended June 30, 2014 was primarily the result of increased production volumes and revenues, offset by increases in cash operating costs, interest expense, and changes in working capital levels.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas, NGLs, and oil production. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather, infrastructure, capacity to reach markets and other variable factors influence 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, 2014, we used cash totaling $1.8 billion in investing activities, including $1.1 billion for drilling and completion costs, $239 million for undeveloped leasehold acquisitions, $100 million for fresh water distribution facilities, $262 million for gathering and compression systems, and $11 million for other property and equipment. During the six months ended June 30, 2013, we used cash totaling $1.2 billion in investing activities, including $721 million for drilling and completion costs, $271 million for undeveloped leasehold acquisitions, $37 million for fresh water distribution systems, and $152 million of expenditures for gathering and compression systems.

Our board of directors has approved a capital budget of $2.85 billion for 2014. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2014 of $1.3 billion consisted of net additional borrowings on our Credit Facility of $952 million and the issuance of $600 million of our 5.125% Senior Notes, net of $294 million for retirements of senior notes and payments for early redemption premiums and deferred financing costs. Net cash provided by financing activities of $978 million for the six months ended June 30, 2013 resulted from the issuance of $225 million of our 6.00% Senior Notes at a premium of 3%, $743 million of net additional borrowings on our Credit Facility, net of payments of deferred financing costs on the issuance of the senior notes of $3.0 million, and other items of $3 million.

Senior Secured Revolving Credit Facility. On July 28, 2014, the Credit Facility was amended to increase lender commitments from $2 billion to $2.5 billion, including $400 million of commitments under the midstream credit facility. The letter of credit sublimit was increase from $500 million to $650 million. Maximum borrowings under the facility are $3.5 billion and the current borrowing base is $3.0 billion. Lender commitments can be increased to the full $3.0 billion upon the approval of the lenders. The maturity date of the facility is May 2019. The borrowing base is redetermined semi-annually and is based on the lenders   judgment of the volume of our proved oil and gas reserves and the estimated future cash flows from these reserves and the value of our hedge positions. The next redetermination is scheduled to occur in October 2014. At June 30, 2014, we had $1.24 billion of borrowings and $237 million of letters of credit outstanding under the Credit Facility. At December 31, 2013, we had $288 million of borrowings and $32 million of letters of credit outstanding under the Credit Facility.

The Credit Facility and the Midstream Facility are ratably secured by mortgages on substantially all of our properties and guarantees from the Company or its subsidiaries, as applicable. Interest is payable at a variable rate based on LIBOR or the prime rate based on our election at the time of borrowing.

The Credit Facility and the Midstream Facility contain certain covenants, including restrictions on indebtedness, asset sales, investments, liens, dividends, hedging, and certain other transactions without the prior consent of the lenders. We are required to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (includes unused borrowing base under the Credit Facility and excludes 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, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2013 and as of June 30, 2014.

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

We also have $1 billion of 5.375% senior notes outstanding, which are due November 1, 2021. The 2021 notes are unsecured and effectively subordinated to the Credit Facility and the Midstream Facility to the extent of the value of the collateral securing such facilities. The 2021 notes rank parri passu to our other outstanding senior notes. The 2021 notes are guaranteed by our existing 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 prior to May 1, 2015, we may redeem all, but not less than all, of the 2021 notes at a redemption price equal to 110% of the principal amount of the 2021 notes. 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 $600 million of 5.125% senior notes outstanding, which are due December 1, 2022. The 2022 notes are unsecured and effectively subordinated to the Credit Facility and the Midstream Facility to the extent of the value of the collateral securing such facilities. The 2022 notes rank parri passu to our other outstanding senior notes. The 2022 notes are guaranteed by our existing 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 2021 notes at any time on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, we may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125%. At any time prior to June 1, 2017, we may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a make-whole premium and accrued interest. If we undergo a change of control prior to December 1, 2015, we may redeem all, but not less than all, of the 2022 notes at a redemption price equal to 110% of the principal amount of the 2022 notes. If we undergo a change of control, the holders of the 2022 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued interest.

We 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, 2013 and June 30, 2014.

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 June 1, 2015. At June 30, 2014 and December 31, 2013, there were no outstanding borrowings under this facility.

Non-GAAP Financial Measure

Adjusted EBITDAX is a non-GAAP financial measure that we define as net income (loss) 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, exploration expense, franchise taxes, stock compensation, business acquisition expenses, loss on early extinguishment of debt, and gain or loss on sale of assets. Adjusted EBITDAX, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDAX provides no information regarding a company s capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

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

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

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

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There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net loss from operations to Adjusted EBITDAX and a reconciliation of 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)	**2013**	**2014**	**2013**	**2014**
Net income (loss) from continuing operations	$ 131,193	$ (44,495)	$ 83,196	(139,254)
Commodity derivative fair value (gains) losses(1)	(195,483)	123,766	(123,542)	372,695
Net cash receipts (payments) on settled derivative instruments(1)	14,146	953	62,277	(118)
Interest expense	33,468	37,260	63,396	68,602
Loss on early extinguishment of debt		20,386		20,386
Income tax expense (benefit)	83,725	(18,454)	53,325	(59,116)
Depreciation, depletion, amortization, and accretion	52,856	105,463	93,484	196,971
Impairment of unproved properties	4,803	1,956	6,359	3,353
Exploration expense	7,300	6,703	11,662	13,700
Stock compensation expense		32,474		61,611
State franchise taxes	600	450	1,200	1,288
Adjusted EBITDAX from continuing operations	132,608	266,462	251,357	540,118
Net income from discontinued operations		2,210		2,210
Gain on sale of assets		(3,564)		(3,564)
Income tax expense		1,354		1,354
Adjusted EBITDAX from discontinued operations				
Total adjusted EBITDAX	132,608	266,462	251,357	540,118
Interest expense	(33,468)	(37,260)	(63,396)	(68,602)
Exploration expense	(7,300)	(6,703)	(11,662)	(13,700)
Changes in current assets and current liabilities	(10,238)	3,886	14,723	40,532
State franchise taxes	(600)	(450)	(1,200)	(1,288)
Other noncash items	1,188	(2,213)	2,575	969
Net cash provided by operating activities	$ 82,190	223,722	192,397	498,029

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

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 accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. Our more significant accounting policies and estimates include the successful efforts method of accounting for oil and gas production activities, estimates of natural gas and oil reserve quantities and standardized measures of future cash flows, and impairment of unproved properties. We provide an expanded discussion of our more significant accounting policies, estimates and judgments in our 2013 Form 10-K. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. Also, see note 2 of the notes to our audited consolidated financial statements, included in our 2013 Form 10-K, for a discussion of additional accounting policies and estimates made by management.

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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 U.S. GAAP when it becomes effective. The new standard is effective for the Company on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 will have on its consolidated financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases. See Contractual Obligations for commitments under operating leases, drilling rig and frac service agreements, firm transportation, and gas processing and compression service agreements.

Contractual Obligations

Contractual Obligations. A summary of our contractual obligations as of June 30, 2014 is provided in the following table.

	Year						
(in millions)	**1**	**2**	**3**	**4**	**5**	**Thereafter**	**Total**
Credit Facility(1)	$	$ 320	$	$	$ 920	$	$ 1,240
Senior notes principal(2)						2,125	2,125
Senior notes interest(2)	119	116	116	116	116	262	845
Drilling rig and frac service commitments(3)	199	114	43				356
Firm transportation (4)	227	417	622	646	658	7,814	10,384
Gas processing, gathering, and compression services (5)	205	206	227	230	202	1,093	2,163
Office and equipment leases	8	7	7	5	5	12	44
Asset retirement obligations(6)						13	13
Total	$ 758	$ 1,180	$ 1,015	$ 997	$ 1,901	$ 11,319	$ 17,170

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(1) Includes outstanding principal amount at June 30, 2014. This table does not include future commitment fees, interest expense or other fees on the Credit 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, and the 5.125% notes due 2022.

(3) At June 30, 2014, we had contracts for the services of 20 rigs which expire at various dates from 2014 through 2016. We also had 4 frac services contracts which expire at various dates from 2014 through 2017. 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) We have entered into 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 a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(5) Contractual commitments for gas processing, gathering and compression services agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression 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.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk.

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

Commodity Price Risk

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

To mitigate some of the potential negative impact on our cash flow caused by changes in natural gas and oil prices, we have entered into financial commodity swap contracts to receive fixed prices for a portion of our natural gas and oil production when management believes that favorable future prices can be secured.

Our financial hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas and oil price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. These contracts may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, cashless price collars that set a floor and ceiling price for the hedged production, or basis differential swaps. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference.

At June 30, 2014, we had in place natural gas and oil swaps covering portions of our projected production from 2014 through 2019. Our hedge position as of June 30, 2014 is summarized in note 7 to our consolidated financial statements included elsewhere herein. Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas and oil price fluctuations. Our Credit Facility allows us to hedge up to 85% of our estimated production from proved reserves for up to 12 months in the future, 80% for 13 to 24 months in the future, 75% for 25 to 36 months in the future, 70% for 37 to 48 months in the future, 65% for 49 to 60 months in the future, and 65% of production for 2019. Based on our production and our fixed price swap contracts in place during the six months ended June 30, 2014, we estimate that revenues from production, as adjusted for cash settled derivatives, for the six months ended June 30, 2014 would have decreased by approximately $3 million for each $0.10 decrease per MMBtu in natural gas prices and $1.00 decrease per Bbl in oil and NGL prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception as mentioned above, are recorded at fair market value in accordance with United States GAAP and are included in the consolidated balance sheets as assets or liabilities. Fair values are adjusted for non-performance risk. Because we do not designate these hedges as accounting hedges, we do not receive accounting hedge treatment and all mark-to-market gains or losses as well as realized gains or losses on the derivative instruments are recognized in our results of operations. We present realized and unrealized gains or losses on commodity derivatives in our operating revenues as Commodity derivative fair value gains (losses) .

Mark-to-market adjustments of derivative instruments produce 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 flow is only impacted when the underlying physical sales transaction takes place in the future and when the associated derivative instrument contract is settled by making or receiving a payment to or from the counterparty. At June 30, 2014, the estimated fair value of our commodity derivative instruments was a net asset of $488 million comprised of current and noncurrent assets and current and noncurrent liabilities. At December 31, 2013, the estimated fair value of our commodity derivative instruments was a net asset of $860 million comprised of current and noncurrent assets and current liabilities.

By removing price volatility from a portion of our expected natural gas and oil production through December 2019, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow 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.

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Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($488 million at June 30, 2014) and the sale of our oil and gas production ($140 million at June 30, 2014).

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with ten different counterparties, all of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately $488 million at June 30, 2014 includes the following values by bank counterparty: BNP Paribas - $176 million; Credit Suisse - $112 million; Wells Fargo - $92 million; JP Morgan - $91 million; Barclays - $45 million; and Deutsche Bank - $14 million. The credit ratings of certain of these banks were downgraded in recent years because of the sovereign debt crisis in Europe. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at June 30, 2014 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 contracts, nor are they required to provide credit support to us. As of June 30, 2014, we have no past due receivables from or payables to any of our counterparties.

We are also subject to credit risk due to 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.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility, which has a floating interest rate. The average annual interest rate incurred on this indebtedness for the six months ended June 30, 2014, was approximately 2%. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the six months ended June 30, 2014 would have resulted in an estimated $3.5 million increase in interest expense for the six months ended June 30, 2014.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended (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. 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, 2014 at the reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change 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, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings.

In March 2011, we received orders for compliance from the U.S. Environmental Protection Agency (the EPA) relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations pertaining to unpermitted discharges of fill material into wetlands or waters 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.

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

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

Item 1A. Risk Factors.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. For a discussion of these risks, see Item 1A. Risk Factors in our 2013 Form 10-K. The risks described in our 2013 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 2013 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 5. Other Information.

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

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

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

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

Antero Resources Corporation understands that SAMIH s affiliates intend to disclose in their next annual or quarterly SEC report that an Iranian national, resident in the U.K., who is currently designated by the U.S. under the Iranian Financial Sanctions Regulations and the NPWMD designation, holds two investment accounts with Santander Asset Management UK Limited. The accounts have remained frozen throughout 2013 and the first half of 2014. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue for the Santander Group in connection with the investment accounts was £23,200 and net profits in the first half of 2014 were negligible relative to the overall profits of Banco Santander, S.A.

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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 Form 10-Q and are incorporated herein by reference.

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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	
Date: August 6, 2014	By:	/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr. *President and Chief Financial Officer* (Duly Authorized Officer and Principal Financial Officer)

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EXHIBIT INDEX

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).
4.1	Indenture related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among the Company, the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.2	Form of 5.125% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.3	Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation, the subsidiary guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
10.1	Eleventh Amendment to Fourth Amended and Restated Credit Agreement, dated as of May 5, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
10.2	First Amendment to Credit Agreement, dated as of May 5, 2014, by and among Antero Midstream LLC, certain subsidiaries of the Borrow, as Guarantors, the Lenders party thereto, and J.P. Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
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 Form 10-Q of Antero Resources Corporation for the quarter ended June 30, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Cash Flows, and (iv) Notes to the Consolidated Financial Statements, tagged as blocks of text.

The exhibits marked with the asterisk symbol (*) are filed or furnished (in the case of Exhibits 32.1 and 32.2) with this Form 10-Q.