ANTERO RESOURCES APPALACHIAN CORP
Form 424B3
April 01, 2013

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Registration Statement No. 333-187430

PROSPECTUS

Offer to Exchange
Up To $525,000,000 of
6.0% Senior Notes due 2020
That Have Not Been Registered Under
The Securities Act of 1933
For
Up To $525,000,000 of
6.0% Senior Notes due 2020
That Have Been Registered Under
The Securities Act of 1933

Terms of the New 6.0% Senior Notes due 2020 Offered in the Exchange Offer:

The terms of the new notes are identical to the terms of the old notes that were issued on November 19, 2012 and February 4, 2013, except that the new notes will be registered under the Securities Act of 1933 and will not contain restrictions on transfer, registration rights or provisions for additional interest.

Terms of the Exchange Offer:

We are offering to exchange up to $525,000,000 of our old notes for new notes with materially identical terms that have been registered under the Securities Act of 1933 and are freely tradable.

We will exchange all old notes that you validly tender and do not validly withdraw before the exchange offer expires for an equal principal amount of new notes.

The exchange offer expires at 11:59 p.m., New York City time, on April 26, 2013, unless extended.

Tenders of old notes may be withdrawn at any time prior to the expiration of the exchange offer.

The exchange of new notes for old notes will not be a taxable event for U.S. federal income tax purposes.

Broker-dealers who receive new notes pursuant to the exchange offer acknowledge that they will deliver a prospectus in connection with any resale of such new notes.

Broker-dealers who acquired the old notes as a result of market-making or other trading activities may use the prospectus for the exchange offer, as supplemented or amended, in connection with resales of the new notes.

You should carefully consider the risk factors beginning on page 8 of this prospectus before participating in the exchange offer.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is April 1, 2013

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This prospectus is part of a registration statement we filed with the Securities and Exchange Commission. In making your investment decision, you should rely only on the information contained in this prospectus and in the accompanying letter of transmittal. We have not authorized anyone to provide you with any other information. We are not making an offer to sell these securities or soliciting an offer to buy these securities in any jurisdiction where an offer or solicitation is not authorized or in which the person making that offer or solicitation is not qualified to do so or to anyone whom it is unlawful to make an offer or solicitation. You should not assume that the information contained in this prospectus is accurate as of any date other than its date.

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In this prospectus we refer to the notes to be issued in the exchange offer as the "new notes" or "new Notes," and we refer to the $525 million principal amount of our 6.0% senior notes due 2020 issued on November 19, 2012 ($300 million) and February 4, 2013 ($225 million) collectively as the "old notes" or "old Notes." We refer to the new notes and the old notes collectively as the "notes." In this prospectus, references to the "issuer" refer to Antero Resources Finance Corporation, a Delaware corporation and an indirect wholly owned subsidiary of Antero Resources LLC, a Delaware limited liability company. Antero Resources Finance Corporation was formed to be the issuer of the notes. References to "Antero," "Antero Resources" or "the Company" refer to Antero Resources LLC unless otherwise indicated or the context otherwise requires. References to "operating subsidiaries" refer to Antero's principal operating subsidiaries, Antero Resources Appalachian Corporation, a Delaware corporation, and Antero Resources Bluestone LLC, a Delaware limited liability company. On March 6, 2013, Antero Resources Arkoma LLC, Antero Resources Piceance LLC and Antero Resources Pipeline LLC were merged into Antero Resources Appalachian Corporation. References to "we," "us" or "our" refer to Antero and its subsidiaries, unless otherwise indicated or the context otherwise requires. References to "guarantors" refer to Antero and each of its subsidiaries that guarantee amounts outstanding on the notes on a joint and several basis.

This prospectus incorporates important business and financial information about us that is not included or delivered with this prospectus. Such information is available without charge to holders of old notes upon written or oral request made to Antero Resources Finance Corporation, 1625 17th Street, Denver, Colorado, 80202, Attention: Chief Financial Officer (Telephone (303) 357-7310). To obtain timely delivery of any requested information, holders of old notes must make any request no later than five business days prior to the expiration of the exchange offer.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus 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 prospectus, 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 in this prospectus, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Risk Factors" included in this prospectus. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- 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 gathering and other midstream operations;
- general economic conditions;

- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this prospectus 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, 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 "Risk Factors" in this prospectus.

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Reserve engineering is a process of estimating underground accumulations of natural gas 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 and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this prospectus 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 prospectus 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 prospectus.

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PROSPECTUS SUMMARY

This summary highlights some of the information contained in this prospectus and does not contain all of the information that may be important to you. You should read this entire prospectus and the documents to which we refer you before making an investment decision. You should carefully consider the information set forth under "Risk Factors" beginning on page 8 of this prospectus and the other cautionary statements described in this prospectus. In addition, certain statements include forward looking information that involves risks and uncertainties. See "Cautionary Statement Regarding Forward-Looking Statements." The information in this prospectus with respect to our estimated proved reserves as of December 31, 2012 has been prepared by our internal reserve engineers and audited by our independent reserve engineering firms. Certain operational terms used in this prospectus are defined in "Annex B: Glossary of Natural Gas and Oil Terms."

Our Company

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2012, we held approximately 371,000 net acres of rich gas and dry gas properties, which are 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 through internally generated projects on our acquired acreage. As of December 31, 2012, our estimated proved reserves were approximately 4.9 Tcfe, consisting of 3.7 Tcf of natural gas, 203 MMBbl of NGLs, and 3 MMBbl of oil.

As of December 31, 2012, 75% of our proved reserves were natural gas, 21% were proved developed and 98% were operated by us. For the year ended December 31, 2012, we generated cash flow from operations of $332 million, a net loss of $285 million and EBITDAX of $434 million. The net loss in 2012 includes, (i) a pre-tax loss of $796 million on the sale of the Arkoma and Piceance Basin properties, (ii) deferred tax benefit related to the loss on the sale of the Arkoma and Piceance properties and discontinued operations of $273 million, (iii) a pre-tax gain on the sale of certain Appalachian gathering systems of $291 million, and (iv) a noncash tax provision related to continuing operations of $121 million. See "Selected Historical Consolidated Financial Data" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

We have assembled a diversified portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus, Utica and Upper Devonian Shales of the Appalachian Basin. From inception, we have drilled and operated 520 wells through December 31, 2012 with a success rate of approximately 98%. Our drilling inventory consists of approximately 4,900 potential well locations, all of which are unconventional resource opportunities.

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

We operate in one industry segment, which is the exploration, development and production of natural gas, NGLs, and oil, and all of our operations are conducted in the United States. Our gathering assets are primarily dedicated to supporting the natural gas volumes we produce.

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Corporate Sponsorship and Structure

We began operations in 2004 and the Company, as it exists today, was formed in October 2009. We have funded our development and operating activities primarily through equity capital raised from private equity sponsors and institutional investors, issuance of debt securities, sales of non-core assets, borrowings under our bank credit facilities, and operating cash flows. Our primary private equity sponsors are affiliates of Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners.

Antero Resources Finance Corporation was formed in October 2009 as an indirect wholly-owned subsidiary of Antero for the purpose of arranging financing for Antero and the operating subsidiaries, including the 9.375% senior notes due 2017, 7.25% senior notes due 2019 and 6.0% senior notes due 2020. The indentures governing the notes limit Antero Finance's activities to those of a finance subsidiary. Antero Finance does not own any significant assets other than intercompany obligations.

Corporate Headquarters

Our corporate headquarters are located at 1625 17th Street, Denver, Colorado 80202, and our telephone number at that address is (303) 357-7310.

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The Exchange Offer

On November 19, 2012 and February 4, 2013, we completed private offerings of $300 million and $225 million, respectively, of the old notes. On each of those dates, we entered into registration rights agreements with the initial purchasers in connection with the offerings pursuant to which we agreed to deliver to you this prospectus and to use commercially reasonable efforts to complete the exchange offer by November 19, 2013.

Exchange Offer	We are offering to exchange new notes for old notes.
Expiration Date	The exchange offer will expire at 11:59 p.m., New York City time, on April 26, 2013, unless we decide to extend it.
Condition to the Exchange Offer	The registration rights agreements do not require us to accept old notes for exchange if the exchange offer, or the making of any exchange by a holder of the old notes, would violate any applicable law or interpretation of the staff of the Securities and Exchange Commission. The exchange offer is not conditioned on a minimum aggregate principal amount of old notes being tendered.
Procedures for Tendering Old Notes	To participate in the exchange offer, you must follow the procedures established by The Depository Trust Company, which we call "DTC," for tendering notes held in book-entry form. These procedures, which we call "ATOP," require that (i) the exchange agent receive, prior to the expiration date of the exchange offer, a computer generated message known as an "agent's message" that is transmitted through DTC's automated tender offer program, and (ii) DTC confirms that: DTC has received your instructions to exchange your notes, and you agree to be bound by the terms of the letter of transmittal. For more information on tendering your old notes, please refer to the section in this prospectus entitled "Exchange Offer Terms of the Exchange Offer," " Procedures for Tendering," and "Description of Notes Book Entry; Delivery and Form."
Guaranteed Delivery Procedures	None.
Withdrawal of Tenders	You may withdraw your tender of old notes at any time prior to the expiration date. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before 11:59 p.m., New York City time, on the expiration date of the exchange offer. Please refer to the section in this prospectus entitled "Exchange Offer Withdrawal of Tenders."
Acceptance of Old Notes and Delivery of New Notes	If you fulfill all conditions required for proper acceptance of old notes, we will accept any and all old notes that you properly tender in the exchange offer before 11:59 p.m., New York City time on the expiration date. We will return any old note that we do not accept for exchange to you without expense promptly after the expiration date and acceptance of the old notes for exchange. Please refer to the section in this prospectus entitled "Exchange Offer Terms of the Exchange Offer."

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Fees and Expenses	We will bear expenses related to the exchange offer. Please refer to the section in this prospectus entitled "Exchange Offer Fees and Expenses."
Use of Proceeds	The issuance of the new notes will not provide us with any new proceeds. We are making this exchange offer solely to satisfy our obligations under the registration rights agreements.
Consequences of Failure to Exchange Old Notes	If you do not exchange your old notes in this exchange offer, you will no longer be able to require us to register the old notes under the Securities Act except in limited circumstances provided under the registration rights agreements. In addition, you will not be able to resell, offer to resell or otherwise transfer the old notes unless we have registered the old notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act.
U.S. Federal Income Tax Consequences	The exchange of new notes for old notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read "Material United States Federal Income Tax Consequences."
Exchange Agent	We have appointed Wells Fargo Bank, N.A. as exchange agent for the exchange offer. You should direct questions and requests for assistance, requests for additional copies of this prospectus or the letter of transmittal to the exchange agent as follows: *By Registered & Certified Mail:* Wells Fargo Bank, N.A. Corporate Trust Operations MAC N9303-121 PO Box 1517 Minneapolis, Minnesota 55480 *By regular mail or overnight courier:* Wells Fargo Bank, N.A. Corporate Trust Operations MAC N9303-121 Sixth & Marquette Avenue Minneapolis, Minnesota 55479 *In person by hand only:* Wells Fargo Bank, N.A. 12th Floor Northstar East Building Corporate Trust Operations 608 Second Avenue South Minneapolis, Minnesota 55402 Eligible institutions may make requests by facsimile at (612) 667-6282 and may confirm facsimile delivery by calling (800) 344-5128.

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Terms of the New Notes

The new notes will be identical to the old notes except that the new notes are registered under the Securities Act and will not have restrictions on transfer, registration rights or provisions for additional interest. The new notes will evidence the same debt as the old notes, and the same indenture will govern the new notes and the old notes.

The following summary contains basic information about the new notes and is not intended to be complete. It does not contain all information that may be important to you. For a more complete understanding of the new notes, please refer to the section entitled "Description of Notes" in this prospectus.

Issuer	Antero Resources Finance Corporation
Securities Offered	$525 million aggregate principal amount of 6.0% senior notes due 2020.
Maturity	December 1, 2020.
Interest Payment Dates	Interest on the notes will be paid semi-annually in arrears on June 1 and December 1 of each year commencing on June 1, 2013. Interest on each new note will accrue from the last interest payment date on which interest was paid on the old note tendered in exchange thereof, or, if no interest has been paid on the old note, from the date of the original issue of the old note.
Guarantees	The payment of the principal, premium and interest on the notes will be fully and unconditionally guaranteed on a senior unsecured basis by Antero, all of its wholly owned subsidiaries (other than the issuer) and certain of its future restricted subsidiaries. The guarantees will be unsecured senior indebtedness of the guarantors and will have the same ranking with respect to the guarantors' indebtedness as the notes will have with respect to the issuer's indebtedness. See "Description of Notes Guarantees."
Ranking	The new notes will be the issuer's general senior unsecured obligations. The new notes will:
	rank equally in right of payment with all of the issuer's other senior indebtedness (including the issuer's guarantee under our senior secured revolving credit facility, our 9.375% senior notes due 2017, our 7.25% senior notes due 2019 and our 9% note payable due December 1, 2013); and
	rank senior in right of payment to any of the issuer's future subordinated indebtedness.
	The guarantees will be the guarantors' general senior unsecured obligations and will rank equally in right of payment with all of the other senior indebtedness of the guarantors (including the guarantors' borrowings under our senior secured revolving credit facility).

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The notes and guarantees will effectively rank junior in right of payment to all of the issuer's and the guarantors' existing and future secured indebtedness, including borrowings and guarantees under our senior secured revolving credit facility, to the extent of the value of the collateral securing such indebtedness.

The notes and guarantees will be structurally subordinated to any liabilities (including trade payables) of any future non-guarantor subsidiaries.

Optional Redemption

The issuer will have the option to redeem the new notes, in whole or in part, at any time on or after December 1, 2015, in each case at the redemption prices described in this prospectus under the heading "Description of Notes Optional Redemption," together with any accrued and unpaid interest to, but excluding, the date of such redemption.

On or prior to December 1, 2015, the issuer may, from time to time, redeem up to 35% of the aggregate principal amount of the notes with the net proceeds of certain equity offerings at a redemption price equal to 106.0% of the principal amount of the notes, plus any accrued and unpaid interest to, but excluding, the date of such redemption.

In addition, at any time prior to December 1, 2015, the issuer may redeem the new notes, in whole or in part, at a "make-whole" redemption price described under "Description of Notes Optional Redemption," together with any accrued and unpaid interest to, but excluding, the date of such redemption.

If certain transactions that would constitute a change of control occur prior to January 1, 2014, we may redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the notes redeemed plus any accrued and unpaid interest to, but excluding, the date of such redemption.

Mandatory Offers to Purchase

Upon the occurrence of a change of control, unless the issuer has exercised its optional redemption right in respect of the notes, holders of the new notes will have the right to require the issuer to repurchase all or a portion of the new notes at a price equal to 101% of the aggregate principal amount of the new notes, together with any accrued and unpaid interest to, but excluding, the date of purchase. In connection with certain asset dispositions, the issuer will be required to use the net cash proceeds of the asset dispositions to make an offer to purchase the new notes at 100% of the principal amount, together with any accrued and unpaid interest to, but excluding, the date of purchase.

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Certain Covenants	The issuer will issue the new notes under an indenture with Wells Fargo Bank, National Association, as trustee, dated as of November 19, 2012. The indenture, among other things, limits the ability of Antero and its restricted subsidiaries (including the issuer) to: incur, assume or guarantee additional indebtedness or issue preferred stock; pay dividends on equity securities, repurchase equity securities or redeem subordinated indebtedness; issue certain preferred stock or similar equity securities; make investments or other restricted payments; create liens to secure indebtedness; restrict dividends, loans or other asset transfers from our restricted subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; enter into transactions with affiliates; and consolidate with or merge with or into, or sell substantially all of our properties to, another person. However, many of these covenants will terminate if: both Standard & Poor's Ratings Services and Moody's Investors Service, Inc. assign the notes an investment grade rating; and no default under the indenture has occurred and is continuing. These covenants are subject to important exceptions and qualifications, which are described under "Description of Notes Certain Covenants."
Absence of a Public Market for the New Notes	The new notes generally will be freely transferable, but will also be new securities for which there will not initially be a market. There can be no assurance as to the development or liquidity of any market for the new notes. We do not intend to apply for a listing of the new notes on any securities exchange or any automated dealer quotation system.
Risk Factors	Investing in the new notes involves risks. See "Risk Factors" beginning on page 8 for a discussion of certain factors you should consider in evaluating whether or not to tender your old notes.

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RISK FACTORS

Investing in the notes involves risks. You should carefully consider the information in this prospectus, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements," and the following risks before participating in the exchange offer.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows, and results of operations, are not the only risks we face. 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.

Risks Relating to the Exchange Offer

If you do not properly tender your old notes, you will continue to hold unregistered old notes and your ability to transfer old notes will remain restricted and may be adversely affected.

The issuer will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes and you should carefully follow the instructions on how to tender your old notes. Neither we nor the exchange agent is required to tell you of any defects or irregularities with respect to your tender of old notes.

If you do not exchange your old notes for new notes pursuant to the exchange offer, the old notes you hold will continue to be subject to the existing transfer restrictions. In general, you may not offer or sell the old notes except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not plan to register old notes under the Securities Act unless the registration rights agreements with the initial purchasers of the old notes require us to do so. Further, if you continue to hold any old notes after the exchange offer is consummated, you may have trouble selling them because there will be fewer of the old notes outstanding.

Risks Relating to the Notes

Our substantial indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under the notes.

We have, and after this exchange will continue to have, a significant amount of indebtedness. As of December 31, 2012, after giving effect to our February 2013 offering of $225 million of the existing notes, the resulting borrowing base adjustment and the application of the net proceeds therefrom, we have approximately $1.5 billion in total indebtedness, no senior secured indebtedness outstanding and $657 million of available borrowing capacity under our senior secured revolving credit facility (our "Credit Facility") (after deducting $43 million outstanding letters of credit).

Subject to the limits contained in the credit agreement governing our Credit Facility, the indenture governing the notes, the indentures that govern our other series of senior notes and our other debt instruments, we may be able to incur substantial additional debt from time to time to finance working capital, capital expenditures, investments or acquisitions, or for other purposes. If we do so, the risks related to our high level of debt could intensify. Specifically, our high level of debt could have important consequences to the holders of the notes, including:

- making it more difficult for us to satisfy our obligations with respect to the notes and our other debt;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions or other general corporate requirements;

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- requiring a substantial portion of our cash flows to be dedicated to debt service payments instead of other purposes, thereby reducing the amount of cash flows available for working capital, capital expenditures, acquisitions and other general corporate purposes;

- increasing our vulnerability to general adverse economic and industry conditions;

- exposing us to the risk of increased interest rates as certain of our borrowings, including borrowings under our Credit Facility, are at variable rates of interest;

- limiting our flexibility in planning for and reacting to changes in the industry in which we compete;

- placing us at a disadvantage compared to other, less leveraged competitors; and

- increasing our cost of borrowing.

We may not be able to generate sufficient cash to service all of our indebtedness, including the notes, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including the notes, depends on our financial condition and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the notes.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance our indebtedness, including the notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indenture governing the notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our Credit Facility and the indentures governing our senior notes (including the notes) restrict our ability to dispose of assets and use the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

As of December 31, 2012, after giving effect to our February 2013 offering of $225 million of the existing notes, the resulting borrowing base adjustment and the application of the net proceeds therefrom, we expect to have approximately $1.5 billion in total indebtedness, no senior secured indebtedness outstanding and $657 million of available borrowing capacity under our Credit Facility (after deducting $43 million outstanding letters of credit).

On February 4, 2013, the borrowing base under our Credit Facility was decreased by $56 million to $1.22 billion. The lender commitments under the facility can be expanded from $700 million to the full $1.22 billion borrowing base upon bank approval.

In the future, we may not be able to access adequate funding under our Credit Facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness that may result in a decrease in our borrowing base, the outcome of a subsequent semi-annual borrowing base

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redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. In addition, to the extent that the borrowing base under our Credit Facility exceeds the total lender commitments, our borrowing availability will be limited to the aggregate lender commitments. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service all of our indebtedness, including the new notes.

If we are unable to comply with the restrictions and covenants in the agreements governing our senior notes and other indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would impact our ability to make principal and interest payments on the notes.

If we are unable to comply with the restrictions and covenants in the indentures governing our senior notes (including the notes) or in our Credit Facility, or in any future debt financing agreements, there could be a default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting financial ratios and tests, may be affected by events beyond our control. As a result, we cannot assure you that we will be able to comply with these restrictions and covenants or meet these tests. Any default under the agreements governing our indebtedness, including a default under our Credit Facility or the indentures governing our senior notes (including the notes), that is not waived by the requisite number of lenders and the remedies sought by the holders of such indebtedness, could prevent us from paying principal, premium, if any, and interest on the notes and substantially decrease the market value of the notes. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on our indebtedness or if we otherwise fail to comply with the various covenants, including financial and operating covenants in the instruments governing our indebtedness (including covenants in our Credit Facility and in the indentures governing our senior notes), we could be in default under the terms of these agreements. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be immediately due and payable, together with any accrued and unpaid interest;

- the lenders under our Credit Facility could elect to terminate their commitments thereunder, cease making further loans to us and institute foreclosure proceedings against our assets; and

- we could be forced into bankruptcy or liquidation.

If our operating performance declines, in the future we may need to obtain waivers from the requisite number of lenders under our Credit Facility to avoid being in default. If we breach our covenants under our Credit Facility and seek a waiver, we may not be able to obtain a waiver from the required lenders on terms that are acceptable to us, if at all. If this occurs, we would be in default under our Credit Facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation. See " Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities."

The notes and the guarantees are unsecured and effectively subordinated to the rights of our secured indebtedness.

The notes and the guarantees are general unsecured senior obligations ranking effectively junior to all of our existing and future secured indebtedness, including our obligations under our Credit Facility, to the extent of the value of the collateral securing the indebtedness.

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If we were unable to repay such indebtedness under our Credit Facility, the lenders under that facility could foreclose on the pledged assets to the exclusion of holders of the notes, even if an event of default exists under the indenture governing the notes at such time. Furthermore, if the lenders foreclose and sell the pledged equity interests in any guarantor in a transaction permitted under the terms of the indenture governing the notes, then such guarantor will be released from its guarantee of the notes automatically and immediately upon such sale. In any such event, because the notes are not secured by any of such assets or by the equity interests in any such guarantor, it is possible that there would be no assets from which your claims could be satisfied or, if any assets existed, they might be insufficient to satisfy your claims in full.

If the issuer or any guarantor is declared bankrupt, becomes insolvent or is liquidated or reorganized, any of its secured indebtedness will be entitled to be paid in full from its assets or the assets of any guarantor securing that indebtedness before any payment may be made with respect to the notes or the affected guarantees. Holders of the notes will participate ratably in our remaining assets with all holders of any unsecured indebtedness that does not rank junior to the notes, based upon the respective amounts owed to each holder or creditor. In any of the foregoing events, there may not be sufficient assets to pay amounts due on the notes or the guarantees. As a result, holders of the notes would likely receive less, ratably, than holders of secured indebtedness.

As of December 31, 2012, after giving effect to our February 2013 offering of $225 million of the existing notes, the resulting borrowing base adjustment and the application of the net proceeds therefrom, we expect to have approximately $1.5 billion in total indebtedness, no senior secured indebtedness outstanding and $657 million of available borrowing capacity under our Credit Facility (after deducting $43 million outstanding letters of credit).

We may incur substantially more indebtedness, including indebtedness ranking equal to the notes and the guarantees. This could increase the risks associated with the notes.

Subject to the restrictions in the indenture governing the notes, the indentures governing our other senior notes and our Credit Facility, we may incur substantial additional indebtedness (including secured indebtedness) in the future. Although the instruments governing our Credit Facility and the indentures governing our senior notes (including the notes) each contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to certain qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial. These restrictions also will not prevent us from incurring obligations that do not constitute indebtedness.

If the issuer or any guarantor incurs any additional indebtedness that ranks equally with the notes (or with the guarantees thereof), including trade payables, the holders of that indebtedness will be entitled to share ratably with noteholders in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of the issuer or such guarantor. This may have the effect of reducing the amount of proceeds paid to noteholders in connection with such a distribution. As of December 31, 2012, after giving effect to our February 2013 offering of $225 million of the existing notes and the application of the net proceeds therefrom, we would have had total long-term indebtedness of approximately $1.5 billion.

Any increase in our level of indebtedness will have several important effects on our future operations, including, without limitation:

- we will have additional cash requirements in order to support the payment of interest on our outstanding indebtedness;

- increases in our outstanding indebtedness and leverage will increase our vulnerability to adverse changes in general economic and industry conditions, as well as to competitive pressure;

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- depending on the levels of our outstanding indebtedness, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes may be limited; and

- our level of indebtedness may prevent us from engaging in certain transactions that might otherwise be beneficial to us.

Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, business prospects and ability to satisfy our obligations under the notes.

The notes are structurally subordinated to all obligations of our future subsidiaries that do not become guarantors of the notes.

The notes are guaranteed by all of Antero's existing subsidiaries (except the issuer), and by (a) any wholly-owned domestic subsidiary of Antero formed after the issue date of the existing notes and (b) any domestic subsidiary of Antero that guarantees any indebtedness of the issuer, Antero or any other subsidiary guarantor (in each case, other than an immaterial subsidiary). Our subsidiaries that do not guarantee the notes will have no obligation, contingent or otherwise, to pay amounts due under the notes or to make any funds available to pay those amounts, whether by dividend, distribution, loan or other payment. The notes are structurally subordinated to all indebtedness and other obligations of any non-guarantor subsidiary such that in the event of insolvency, liquidation, reorganization, dissolution or other winding up of any subsidiary that is not a guarantor, all of that subsidiary's creditors (including trade creditors) would be entitled to payment in full out of that subsidiary's assets before we would be entitled to any payment.

In addition, the indenture governing the notes, subject to some limitations, permits these subsidiaries to incur additional indebtedness and does not contain any limitation on the amount of other liabilities, such as trade payables, that may be incurred by these subsidiaries.

Further, our subsidiaries that provide, or will provide, guarantees of the notes will be automatically released from those guarantees upon the occurrence of certain events, including the following:

- the designation of that subsidiary guarantor as an unrestricted subsidiary;

- the release or discharge of any guarantee or indebtedness that resulted in the creation of the guarantee of the notes by such subsidiary guarantor; or

- the sale or other disposition, including the sale of substantially all the assets, of that subsidiary guarantor.

If any subsidiary guarantee is released, no holder of the notes will have a claim as a creditor against that subsidiary, and the indebtedness and other liabilities, including trade payables and preferred stock, if any, whether secured or unsecured, of that subsidiary will be effectively senior to the claim of any holders of the notes. See "Description of Notes Guarantees."

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our Credit Facility contains a number of significant restrictive covenants (in addition to covenants restricting the incurrence of additional indebtedness) that may limit our ability to, among other things:

- sell assets;

- make loans to others;

- make investments;

enter into mergers;

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- make certain payments;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The indentures governing our senior notes (including the notes) contain similar restrictive covenants. In addition, our Credit Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indentures governing our senior notes (including the notes), may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing our senior notes (including the notes) and our Credit Facility impose on us.

Our Credit Facility limits the amounts we can borrow up to the lesser of (a) the total commitments or (b) a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the natural gas properties securing our loan. Currently, our Credit Facility has a borrowing base of $1.22 billion, but the total lender commitments are only $700 million but can be expanded to the full $1.22 billion borrowing base upon bank approval.

The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. Increases in total lender commitments require the approval of the individual lenders who wish to increase their commitment.

Outstanding borrowings in excess of the borrowing base must be repaid, or we must pledge other natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our Credit Facility.

A breach of any covenant in our Credit Facility would result in a default under that agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. In addition, an event of default under our Credit Facility would permit the lenders under our Credit Facility to terminate all commitments to extend further credit under that facility. Furthermore, if we were unable to repay the amounts due and payable under our Credit Facility, those lenders could proceed against the collateral granted to them to secure that indebtedness.

If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements and Contractual Obligations Senior Secured Revolving Credit Facility" and "Description of Notes Events of Default."

Our ability to repay our indebtedness, including the notes, is dependent on the cash flow generated by our operating subsidiaries.

The operating subsidiaries own substantially all of our assets and conduct all of our operations. Accordingly, repayment of our indebtedness, including the notes, will be dependent on the generation of cash flow by the operating subsidiaries and their ability to make such cash available to the issuer, directly or indirectly, by dividend, debt repayment or otherwise. All of the operating subsidiaries guarantee the issuer's obligations under the notes. Unless they guarantee the notes, our future subsidiaries will not have any obligation to pay amounts due on the notes or to make funds available for that purpose. The operating subsidiaries may not be able to, or may not be permitted to, make distributions to enable the issuer to make payments in respect of its indebtedness, including the notes. Each operating subsidiary is a distinct legal entity and, under certain circumstances, legal and contractual restrictions may limit the issuer's ability to obtain cash from the operating subsidiaries. While the indentures governing our senior notes (including the notes) and our Credit Facility limit the ability of the operating subsidiaries to incur consensual encumbrances or restrictions on their ability to pay dividends or make other intercompany payments to Antero, those limitations are subject to certain qualifications and exceptions. In the event that we do not receive distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the notes.

Your ability to transfer the notes may be limited by the absence of an active trading market, and an active trading market may not develop for the notes.

The old notes have not been registered under the Securities Act, and may not be resold by holders thereof unless the old notes are subsequently registered or an exemption from the registration requirements of the Securities Act is available. However, we cannot assure you that, even following registration or exchange of the old notes for new notes, an active trading market for the old notes or the new notes will exist, and we will have no obligation to create such a market. At the time of the private placements of the old notes, the initial purchasers advised us that they intended to make a market in the old notes and, if issued, the new notes, as permitted by applicable laws and regulations. However, the initial purchasers are not obligated to make a market in the old notes or the new notes and they may discontinue their market making activities at any time without notice. In addition, market making activities may be limited during an exchange offer or while the effectiveness of a shelf registration statement is pending.

Therefore, an active market for the notes may not develop or be maintained, which would adversely affect the market price and liquidity of the notes. In that case, the holders of the notes may not be able to sell their notes at a particular time or at a favorable price. If a trading market were to develop, future trading prices of the notes may be volatile and will depend on many factors, including:

- the number of holders of notes;
- prevailing interest rates;
- our operating performance and financial condition;
- the interest of securities dealers in making a market for them; and
- the market for similar securities.

Even if an active trading market for the notes does develop or is maintained, there is no guarantee that it will continue. Historically, the market for non-investment grade debt has been subject to severe disruptions that have caused substantial volatility in the prices of securities similar to the notes. The market, if any, for the notes may experience similar disruptions, and any such disruptions may adversely affect the liquidity in that market or the prices at which you may sell your notes. In addition, subsequent to their initial issuance, the old notes or the new notes may trade at a discount from the old notes' initial offering price, depending upon prevailing interest rates, the market for similar notes, our performance and other factors.

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The issuer may not be able to repurchase the notes in certain circumstances.

Under the terms of the indentures governing our senior notes (including the notes), holders may require us to repurchase all or a portion of the outstanding senior notes if we sell certain assets or in the event of a change of control. We may not have enough funds to pay the repurchase price on a purchase date (in which case, we could be required to issue equity securities to pay the repurchase price). Additionally, under our Credit Facility, a change of control (as defined therein) constitutes an event of default that permits the lenders to accelerate the maturity of borrowings under the credit agreement and terminate their commitments to lend. The source of funds for any purchase of our senior notes (including the notes) and repayment of borrowings under our Credit Facility would be our available cash or cash generated from our subsidiaries' operations or other sources, including borrowings, sales of assets or sales of equity. We may not be able to repurchase our outstanding senior notes (including the notes) upon a change of control because we may not have sufficient financial resources to purchase all of the debt securities that are tendered upon a change of control and repay our other indebtedness that will become due. We may require additional financing from third parties to fund any such purchases, and we may be unable to obtain financing on satisfactory terms or at all. Further, our ability to repurchase our outstanding senior notes (including the notes) may be limited by law. In order to avoid the obligations to repurchase our outstanding senior notes (including the notes) and events of default and potential breaches of the credit agreement governing our Credit Facility, we may have to avoid certain change of control transactions that would otherwise be beneficial to us.

In addition, some important corporate events, such as leveraged recapitalizations, may not, under the indentures governing our outstanding senior notes (including the notes), constitute a "change of control" that would require us to repurchase our outstanding senior notes (including the notes), even though those corporate events could increase the level of our indebtedness or otherwise adversely affect our capital structure, credit ratings or the value of the notes. See "Description of Notes Change of Control."

One of the circumstances under which a change of control may occur is upon the sale or disposition of all or substantially all of our consolidated assets. However, the phrase "all or substantially all" will likely be interpreted under applicable state law and will be dependent upon particular facts and circumstances. As a result, there may be a degree of uncertainty in ascertaining whether a sale or disposition of "all or substantially all" of our consolidated assets has occurred, in which case, the ability of a holder of the notes to obtain the benefit of an offer to repurchase all or a portion of the notes held by such holder may be impaired.

The exercise by the holders of notes of their right to require us to repurchase the notes pursuant to a change of control offer could cause a default under the agreements governing our other indebtedness, including future agreements, even if the change of control itself does not, due to the financial effect of such repurchases on us. In the event a change of control offer is required to be made at a time when we are prohibited from purchasing notes, we could attempt to refinance the borrowings that contain such prohibitions. If we do not obtain a consent or repay those borrowings, we will remain prohibited from purchasing notes. In that case, our failure to purchase tendered notes would constitute an event of default under the indenture which could, in turn, constitute a default under our other indebtedness.

Any guarantees of the notes by Antero or the operating subsidiaries could be deemed fraudulent conveyances under certain circumstances, and a court may subordinate or void the guarantees.

Antero and the operating subsidiaries are the current guarantors of the notes. In certain circumstances, any of Antero's future subsidiaries may be required to guarantee the notes. A court

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could subordinate or void the guarantees under various fraudulent conveyance or fraudulent transfer laws. Generally, to the extent that a U.S. court were to find that at the time the guarantee was entered:

- the guarantee was incurred with the intent to hinder, delay, or defraud any present or future creditor, or contemplated insolvency with a design to favor one or more creditors to the exclusion of others; or

- the guarantor did not receive fair consideration or reasonably equivalent value for issuing the guarantee and, at the time the guarantor issued the guarantee, it:

  - was insolvent or became insolvent as a result of issuing the guarantee,

  - was engaged or about to engage in a business or transaction for which its remaining assets constituted unreasonably small capital, or

  - intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they matured;

then the court would void or subordinate the guarantees in favor of the guarantor's other obligations.

As a general matter, value is given for a transfer or an obligation if, in exchange for the transfer or obligation, property is transferred or a valid antecedent debt is secured or satisfied. A court would likely find that a subsidiary guarantor did not receive reasonably equivalent value or fair consideration for its guarantee to the extent the guarantor did not obtain a reasonably equivalent benefit directly or indirectly from the issuance of the notes.

We cannot be certain as to the standards a court would use to determine whether or not we or the guarantors were insolvent at the relevant time or, regardless of the standard that a court uses, whether the notes or the guarantees would be subordinated to our or any of our guarantors' other debt. In general, however, a court would deem an entity insolvent if:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all its assets;

- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they became absolute and mature; or

- it could not pay its debts as they became due.

If a court were to find that the issuance of the notes or the incurrence of a guarantee was a fraudulent transfer or conveyance, the court could void the payment obligations under the notes or that guarantee, could subordinate the notes or that guarantee to presently existing and future indebtedness of ours or of the related guarantor or could require the holders of the notes to repay any amounts received with respect to that guarantee. In the event that a finding that a fraudulent transfer or conveyance occurred, you may not receive any repayment on the notes. Further, the avoidance of the notes could result in an event of default with respect to our and our subsidiaries' other debt that could result in acceleration of that debt.

Finally, as a court of equity, the bankruptcy court may subordinate the claims in respect of the notes to other claims against us under the principle of equitable subordination if the court determines that (1) the holder of notes engaged in some type of inequitable conduct, (2) the inequitable conduct resulted in injury to our other creditors or conferred an unfair advantage upon the holders of notes and (3) equitable subordination is not inconsistent with the provisions of the bankruptcy code.

Each guarantee contains a provision intended to limit the guarantor's liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a

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fraudulent conveyance or fraudulent transfer. This provision may not be effective to protect the guarantees from being voided under applicable law.

A lowering or withdrawal of the ratings assigned to our debt securities by rating agencies may increase our future borrowing costs and reduce our access to capital.

Our debt currently has a non-investment grade rating, and any rating assigned to the notes could be lowered or withdrawn entirely by a rating agency if, in that rating agency's judgment, future circumstances relating to the basis of the rating, such as adverse changes, so warrant. Consequently, real or anticipated changes in our credit ratings will generally affect the market value of the notes. Credit ratings are not recommendations to purchase, hold or sell the notes. Additionally, credit ratings may not reflect the potential effect of risks relating to the structure or marketing of the notes.

Any future lowering of our ratings likely would make it more difficult or more expensive for us to obtain additional debt financing. If any credit rating initially assigned to the notes is subsequently lowered or withdrawn for any reason, you may not be able to resell your notes without a substantial discount.

Many of the covenants contained in the indenture governing the notes will terminate if the notes are rated investment grade by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc.

Many of the covenants in the indenture governing the notes will terminate if the notes are rated investment grade by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc., provided at such time no default under the indenture governing the notes has occurred and is continuing. These covenants will restrict, among other things, our ability to pay dividends, to incur indebtedness and to enter into certain other transactions. There can be no assurance that the notes will ever be rated investment grade, or that if they are rated investment grade, that the notes will maintain such ratings. However, termination of these covenants would allow us to engage in certain transactions that would not be permitted while these covenants were in force. See "Description of Notes Covenant Termination."

Risks Relating to Our Business

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this prospectus, actually occur, our business, financial condition or results of operations could suffer. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect our company.

Natural gas prices are volatile. A substantial or extended decline in natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas is a commodity and, therefore, its prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for natural gas has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas;

- the price and quantity of imports of foreign natural gas, including liquefied natural gas;

- political conditions in or affecting other natural gas-producing countries, including conflicts in the Middle East, Africa, South America, and Russia;
- the level of global natural gas exploration and production;
- the level of global natural gas inventories;
- prevailing prices on local natural gas price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Furthermore, the worldwide financial and credit crisis in recent years has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide resulting in a slowdown in economic activity and recession in parts of the world. This has reduced worldwide demand for energy and resulted in lower natural gas prices. Natural gas spot prices have been particularly volatile and declined from record high levels in early July 2008 of over $13.00 per Mcf to approximately $3.50 per Mcf in March 2013 as a result of increased natural gas supplies and economic conditions.

Continued lower natural gas prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our natural gas reserves as existing reserves are depleted. Continued lower natural gas prices may also reduce the amount of natural gas that we can produce economically.

If natural gas prices remain at their current levels for a significant period of time, a significant portion of our exploration, development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our natural gas reserves.

The natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the development, exploitation, production and acquisition of natural gas reserves. Our cash flow used in investing activities related to capital and exploration expenditures was approximately $1.69 billion in 2012. Our board of directors has approved a capital budget for 2013 of $1.65 billion, including $1.15 billion for drilling and completion, $350 million for the construction of gathering pipelines and facilities in the Appalachian Basin (including $150 million for water-handling infrastructure, primarily in the Marcellus Shale) and $150 million for leasehold. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations, through borrowings under our Credit Facility, the issuance of the old notes, and possibly through additional sales of gathering assets or capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures. Conversely, a

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significant improvement in product prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our Credit Facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness may require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of natural gas we are able to produce from existing wells;
- the prices at which our natural gas is sold;
- our ability to acquire, locate and produce new reserves; and
- the ability of our banks to lend.

If our revenues or the borrowing base under our Credit Facility decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our Credit Facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves, and could adversely affect our business, financial condition and results of operations.

Drilling for and producing natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our natural gas exploration, exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see " Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;

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- equipment failures or accidents;
- adverse weather conditions, such as blizzards, tornados, hurricanes, and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in natural gas prices;
- limited availability of financing at acceptable rates;
- title problems, including in connection with our Utica operations in Ohio, where we have faced claims that certain leases we have acquired are invalid due to production from other horizons being insufficient to hold title by production with respect to the Utica formation rights that we have purchased; and
- limitations in the market for natural gas.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our Credit Facility, our 9.375% senior notes due 2017, our 7.25% senior notes due 2019 and the notes depends on our financial condition and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the senior notes.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance our indebtedness, including the senior notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indentures governing our series of senior notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our Credit Facility and the indentures governing our series of senior notes currently restrict our ability to dispose of assets and use the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

The borrowing base under our Credit Facility is currently $1.22 billion, and lender commitments under the Credit Facility are $700 million. Our next scheduled borrowing base redetermination is expected to occur in May 2013. In the future, we may not be able to access adequate funding under our Credit Facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent semi-annual borrowing base redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations

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and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our Credit Facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness). Our Credit Facility contains restrictive covenants that may limit our ability to, among other things:

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

The indentures governing our series of senior notes contain similar restrictive covenants. In addition, our Credit Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indentures governing our series of senior notes, may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing our series of senior notes and our Credit Facility impose on us.

Our Credit Facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid, or we must pledge other natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our Credit Facility. The borrowing base under our Credit Facility is currently $1.22 billion and lender commitments are $700 million. Our next scheduled borrowing base redetermination is expected to occur in May 2013.

A breach of any covenant in our Credit Facility would result in a default under that agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments

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or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements and Contractual Obligations Senior Secured Revolving Credit Facility" and "Management's Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements and Contractual Obligations Senior Notes."

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and natural gas prices do not improve, our cash flows may be adversely impacted. Additionally, if development drilling costs increase significantly in the future, our hedged revenues may not be sufficient to cover our costs.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, we have entered into a number of hedge contracts for approximately 757 Bcf of our natural gas production from January 1, 2013 through December 31, 2018. We are currently realizing a significant benefit from these hedge positions. For example, for the years ended December 31, 2011 and 2012, we received approximately $117 million and $271 million, respectively, in cash flows pursuant to our hedges. If future natural gas prices remain comparable to current prices, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through December 2018. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected.

Additionally, since we hedge a significant part of our estimated future production, we have fixed a significant part of our future revenue stream. If development drilling costs increase significantly because of inflation, increased demand for oilfield services, increased costs to comply with regulations governing our industry, or other factors, future hedged revenues may not be sufficient to cover our costs.

For additional information regarding our hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk."

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated natural gas reserves. We generally base the estimated

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discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Our identified potential well locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential well locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential well locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

We have approximately 4,900 potential well locations. As a result of the limitations described above, we may be unable to drill many of our potential well locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2012, 79% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 4.9 Tcfe of estimated proved undeveloped reserves will require an estimated $3.3 billion of development capital over the next five years. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

If commodity prices decrease or remain at current levels for a significant period of time, we may be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A writedown constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could

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have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, we enter into derivative instrument contracts for a significant portion of our natural gas production, including collars and price-fix swaps. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, including the notes, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

As of December 31, 2012, the estimated fair value of our commodity derivative contracts was approximately $532 million. Any default by the counterparties to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations. The fair value of our commodity derivative contracts of approximately $532 million at December 31, 2012 includes the following values by bank counterparty: JP Morgan $94 million; BNP Paribas $124 million; Credit Suisse $150 million; Wells Fargo $86 million; Barclays $57 million; Deutsche Bank $11 million; and Union Bank $4 million. Additionally, contracts with Dominion Field Services account for $6 million of the fair value. The credit ratings of certain of these banks were downgraded in 2011 because of the sovereign debt crisis in Europe.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

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The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables ($6 million at December 31, 2012) and the sale of our natural gas production ($47 million in receivables at December 31, 2012), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. The largest purchaser of our natural gas during the twelve months ended December 31, 2012 purchased approximately 23% of our operated production. We 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.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, regional, state and local laws and regulations relating to protection of the environment and worker health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

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

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and worker health and safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters. For example, we have been recently named as the defendant 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. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. We are not yet able to estimate what our aggregate exposure for monetary or other damages resulting from these or other similar claims might be. Also, new laws, regulations or enforcement policies could

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be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting natural gas and oil related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Prospects that we decide to drill may not yield natural gas or oil in commercially viable quantities.

Prospects that we decide to drill that do not yield natural gas or oil in commercially viable quantities will adversely affect our results of operations and financial condition. In this prospectus, we describe some of our current prospects and our plans to explore those prospects. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural

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gas or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures and the amount of hydrocarbons. We are employing 3-D seismic technology with respect to certain of our projects. The implementation and practical use of 3-D seismic technology is relatively new, unproven and unconventional, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns or losses. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 3-D data without having an opportunity to attempt to benefit from those expenditures.

Market conditions or operational impediments may hinder our access to natural gas and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas and oil pipeline or gathering system capacity. In addition, if natural gas or oil quality specifications for the third party natural gas or oil pipelines with which we connect change so as to restrict our ability to transport natural gas or oil, our access to natural gas and oil markets could be

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impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, natural gas. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

Changes to existing or new regulations may unfavorably impact us, could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938, or NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or FERC, as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

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Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD"), construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay or ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity-price, interest-rate, and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), enacted in 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. The position-limits rule was vacated by the U.S. District Court for the District of Colombia in September 2012 and the CFTC recently stated that it will appeal the District Court's decision. The CFTC also finalized other regulations, including critical rulemakings on the definition of "swap," "swap dealer," and "major swap participant." Some regulations, however, remain to be finalized and it is not possible at this time to predict when this will be accomplished. Depending on our classification and the particular nature of our derivative activities, the Dodd-Frank Act and regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities. The Dodd-Frank Act and regulations may also require our counterparties to our derivative instruments to spin off some of our derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less-creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural-gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations, or cash flows.

Competition in the natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Paul M. Rady, our Chairman and Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Seasonal weather conditions and regulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect various wildlife. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, as of December 31, 2012, outstanding borrowings under our Credit Facility were approximately $217 million, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased annual interest expense during 2012 of approximately $3 million and a corresponding decrease in our net income before the effects of increased interest rates on the value of our interest rate swap contracts and income taxes. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our Credit Facility imposes and the indentures governing our series of senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our Credit Facility and the indentures governing our series of senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

The Fiscal Year 2013 Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In February 2013, the governor of the state of Ohio proposed a plan to enact new severance taxes in fiscal 2014 and 2015. Under the plan, the severance taxes for horizontal wells would increase from $0.20 per barrel of oil and $0.03 per MCF of gas to 1% of production revenues for natural gas production revenues and 4% of production revenues for oil, NGLs, and condensate. For the first year of production, a rate of 1.5% would apply to oil, NGLs, and condensate. The passage of these changes would increase our tax burdens in the Utica Shale play in Ohio.

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EXCHANGE OFFER

Purpose and Effect of the Exchange Offer

At the closing of each offering of the old notes, we entered into a registration rights agreement with the initial purchasers pursuant to which we agreed, for the benefit of the holders of the old notes, at our cost, to do the following:

- file an exchange offer registration statement with the SEC with respect to the exchange offer for the new notes, and

- use commercially reasonable efforts to have the exchange offer completed by the 365th day following the date of the initial issuance of the notes (November 19, 2013).

Upon the SEC's declaring the exchange offer registration statement effective, we agreed to offer the new notes in exchange for surrender of the old notes. We agreed to use commercially reasonable efforts to cause the exchange offer registration statement to be effective continuously, and to keep the exchange offer open for a period of not less than 20 business days.

For each old note surrendered to us pursuant to the exchange offer, the holder of such old note will receive a new note having a principal amount equal to that of the surrendered old note. Interest on each new note will accrue from the last interest payment date on which interest was paid on the surrendered old note or, if no interest has been paid on such old note, from November 19, 2012. The registration rights agreements also contain agreements to include in the prospectus for the exchange offer certain information necessary to allow a broker-dealer who holds old notes that were acquired for its own account as a result of market-making activities or other ordinary course trading activities (other than old notes acquired directly from us or one of our affiliates) to exchange such old notes pursuant to the exchange offer and to satisfy the prospectus delivery requirements in connection with resales of new notes received by such broker-dealer in the exchange offer. We agreed to use commercially reasonable efforts to maintain the effectiveness of the exchange offer registration statement for these purposes for a period of 180 days after the completion of the exchange offer, which period may be extended under certain circumstances.

The preceding agreement is needed because any broker-dealer who acquires old notes for its own account as a result of market-making activities or other trading activities is required to deliver a prospectus meeting the requirements of the Securities Act. This prospectus covers the offer and sale of the new notes pursuant to the exchange offer and the resale of new notes received in the exchange offer by any broker-dealer who held old notes acquired for its own account as a result of market-making activities or other trading activities other than old notes acquired directly from us or one of our affiliates.

Based on interpretations by the staff of the SEC set forth in no-action letters issued to third parties, we believe that the new notes issued pursuant to the exchange offer would in general be freely tradable after the exchange offer without further registration under the Securities Act. However, any purchaser of old notes who is an "affiliate" of ours or who intends to participate in the exchange offer for the purpose of distributing the related new notes:

- will not be able to rely on the interpretation of the staff of the SEC,

- will not be able to tender its new notes in the exchange offer, and

- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the old notes unless such sale or transfer is made pursuant to an exemption from such requirements.

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Each holder of the old notes (other than certain specified holders) who desires to exchange old notes for the new notes in the exchange offer will be required to make the representations described below under "   Your Representations to Us."

We further agreed to file with the SEC a shelf registration statement to register for public resale of old notes held by any holder who provides us with certain information for inclusion in the shelf registration statement if:

- the exchange offer is not permitted by applicable law or SEC policy, or
- the exchange offer is not for any reason completed by the 365th day following the date of the initial issuance of the notes (November 19, 2013), or
- upon completion of the exchange offer, any initial purchaser shall so request in connection with any offering or sale of notes.

We have agreed to use commercially reasonable efforts to keep the shelf registration statement continuously effective until the earlier of one year following its effective date and such time as all notes covered by the shelf registration statement have been sold. We refer to this period as the "shelf effectiveness period."

The registration rights agreements provide that, in the event that either the exchange offer is not completed or the shelf registration statement, if required, is not declared effective (or does not automatically become effective) on or prior to the 365th calendar day following the date of the initial issuance of the notes (November 19, 2013), the interest rate on the old notes will be increased by 1.00% per annum until the exchange offer is completed or the shelf registration statement is declared effective (or automatically becomes effective) under the Securities Act, at which time the increased interest shall cease to accrue.

If the shelf registration statement has been declared effective (or automatically becomes effective) and thereafter either ceases to be effective or the prospectus contained therein ceases to be usable for resales of the notes at any time during the shelf effectiveness period, and such failure to remain effective or usable for resales of the notes exists for more than 30 calendar days (whether or not consecutive) in any 12-month period, then the interest rate on the old notes will be increased by 1.00% per annum commencing on the 31st day in such 12-month period and ending on such date that the shelf registration statement has again been declared (or automatically becomes) effective or the prospectus again becomes usable, at which time the increased interest shall cease to accrue.

Holders of the old notes will be required to make certain representations to us (as described in the registration rights agreements) in order to participate in the exchange offer and will be required to deliver information to be used in connection with the shelf registration statement and to provide comments on the shelf registration statement within the time periods set forth in the registration rights agreements in order to have their old notes included in the shelf registration statement.

If we effect the registered exchange offer, we will be entitled to close the registered exchange offer 20 business days after its commencement as long as we have accepted all old notes validly tendered in accordance with the terms of the exchange offer and no brokers or dealers continue to hold any old notes.

This summary of the material provisions of the registration rights agreements do not purport to be complete and is subject to, and is qualified in its entirety by reference to, all the provisions of the registration rights agreements, copies of which are filed as exhibits to the registration statement which includes this prospectus.

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Except as set forth above, after consummation of the exchange offer, holders of old notes which are the subject of the exchange offer have no registration or exchange rights under the registration rights agreements. See " Consequences of Failure to Exchange."

Terms of the Exchange Offer

Subject to the terms and conditions described in this prospectus and in the letter of transmittal, we will accept for exchange any old notes properly tendered and not withdrawn prior to 11:59 p.m., New York City time on the expiration date. We will issue new notes in principal amount equal to the principal amount of old notes surrendered in the exchange offer. Old notes may be tendered only for new notes and only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The exchange offer is not conditioned upon any minimum aggregate principal amount of old notes being tendered for exchange.

As of the date of this prospectus, $525,000,000 in aggregate principal amount of the old notes is outstanding. This prospectus and the letter of transmittal are being sent to all registered holders of old notes. There will be no fixed record date for determining registered holders of old notes entitled to participate in the exchange offer.

We intend to conduct the exchange offer in accordance with the provisions of the registration rights agreements, the applicable requirements of the Securities Act and the Exchange Act and the rules and regulations of the SEC. Old notes that the holders thereof do not tender for exchange in the exchange offer will remain outstanding and continue to accrue interest. These old notes will continue to be entitled to the rights and benefits such holders have under the indenture relating to the notes.

We will be deemed to have accepted for exchange properly tendered old notes when we have given oral or written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration rights agreements. The exchange agent will act as agent for the tendering holders for the purposes of receiving the new notes from us.

If you tender old notes in the exchange offer, you will not be required to pay brokerage commissions or fees or, subject to the letter of transmittal, transfer taxes with respect to the exchange of old notes. We will pay all charges and expenses, other than certain applicable taxes described below, in connection with the exchange offer. It is important that you read the section labeled " Fees and Expenses" for more details regarding fees and expenses incurred in the exchange offer.

We will return any old notes that we do not accept for exchange for any reason without expense to their tendering holder promptly after the expiration or termination of the exchange offer.

Expiration Date

The exchange offer will expire at 11:59 p.m., New York City time, on April 26, 2013, unless, in our sole discretion, we extend it.

Extensions, Delays in Acceptance, Termination or Amendment

We expressly reserve the right, at any time or various times, to extend the period of time during which the exchange offer is open. We may delay acceptance of any old notes by giving oral or written notice of such extension to their holders. During any such extensions, all old notes previously tendered will remain subject to the exchange offer, and we may accept them for exchange.

In order to extend the exchange offer, we will notify the exchange agent orally or in writing of any extension. We will notify the registered holders of old notes of the extension no later than 9:00 a.m., New York City time, on the first business day following the previously scheduled expiration date.

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If any of the conditions described below under " Conditions to the Exchange Offer" have not been satisfied, we reserve the right, in our sole discretion:

- to delay accepting for exchange any old notes,
- to extend the exchange offer, or
- to terminate the exchange offer,

by giving oral or written notice of such delay, extension or termination to the exchange agent. Subject to the terms of the registration rights agreements, we also reserve the right to amend the terms of the exchange offer in any manner.

Any extension, termination or amendment will be followed promptly by oral or written notice thereof to the registered holders of old notes. If we amend the exchange offer in a manner that we determine to constitute a material change, we will promptly disclose such amendment by means of a prospectus supplement. The supplement will be distributed to the registered holders of the old notes. Depending upon the significance of the amendment and the manner of disclosure to the registered holders, we may extend the exchange offer. In the event of a material change in the exchange offer, including the waiver by us of a material condition, we will extend the exchange offer period if necessary so that at least five business days remain in the exchange offer following notice of the material change.

Conditions to the Exchange Offer

We will not be required to accept for exchange, or exchange any new notes for, any old notes if the exchange offer, or the making of any exchange by a holder of old notes, would violate applicable law or any applicable interpretation of the staff of the SEC. Similarly, we may terminate the exchange offer as provided in this prospectus before accepting old notes for exchange in the event of such a potential violation.

In addition, we will not be obligated to accept for exchange the old notes of any holder that has not made to us the representations described under " Purpose and Effect of the Exchange Offer," " Procedures for Tendering" and "Plan of Distribution" and such other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to allow us to use an appropriate form to register the new notes under the Securities Act.

We expressly reserve the right to amend or terminate the exchange offer, and to reject for exchange any old notes not previously accepted for exchange, upon the occurrence of any of the conditions to the exchange offer specified above. We will give prompt oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the old notes as promptly as practicable.

These conditions are for our sole benefit, and we may assert them or waive them in whole or in part at any time or at various times in our sole discretion. If we fail at any time to exercise any of these rights, this failure will not mean that we have waived our rights. Each such right will be deemed an ongoing right that we may assert at any time or at various times.

In addition, we will not accept for exchange any old notes tendered, and will not issue new notes in exchange for any such old notes, if at such time any stop order has been threatened or is in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the indenture relating to the notes under the Trust Indenture Act of 1939.

Procedures for Tendering

In order to participate in the exchange offer, you must properly tender your old notes to the exchange agent as described below. It is your responsibility to properly tender your notes. We have the

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right to waive any defects. However, we are not required to waive defects and are not required to notify you of defects in your tender.

If you have any questions or need help in exchanging your notes, please call the exchange agent, whose contact information is set forth in "Prospectus Summary The Exchange Offer Exchange Agent."

All of the old notes were issued in book-entry form, and all of the old notes are currently represented by global certificates held for the account of DTC. We have confirmed with DTC that the old notes may be tendered using the Automated Tender Offer Program ("ATOP") instituted by DTC. The exchange agent will establish an account with DTC for purposes of the exchange offer promptly after the commencement of the exchange offer and DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer their old notes to the exchange agent using the ATOP procedures. In connection with the transfer, DTC will send an "agent's message" to the exchange agent. The agent's message will state that DTC has received instructions from the participant to tender old notes and that the participant agrees to be bound by the terms of the letter of transmittal.

By using the ATOP procedures to exchange old notes, you will not be required to deliver a letter of transmittal to the exchange agent. However, you will be bound by its terms just as if you had signed it.

There is no procedure for guaranteed late delivery of the notes.

Determinations Under the Exchange Offer

We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered old notes and withdrawal of tendered old notes. Our determination will be final and binding. We reserve the absolute right to reject any old notes not properly tendered or any old notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular old notes. Our interpretation of the terms and conditions of the exchange offer, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of old notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of old notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of old notes will not be deemed made until such defects or irregularities have been cured or waived. Any old notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder, unless otherwise provided in the letter of transmittal, promptly following the expiration date.

When We Will Issue New Notes

In all cases, we will issue new notes for old notes that we have accepted for exchange under the exchange offer only after the exchange agent timely receives:

- a book-entry confirmation of such old notes into the exchange agent's account at DTC; and
- a properly transmitted agent's message.

Return of Old Notes Not Accepted or Exchanged

If we do not accept any tendered old notes for exchange or if old notes are submitted for a greater principal amount than the holder desires to exchange, the unaccepted or non-exchanged old notes will be returned without expense to their tendering holder. Such non-exchanged old notes will be credited

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to an account maintained with DTC. These actions will occur promptly after the expiration or termination of the exchange offer.

Your Representations to Us

By agreeing to be bound by the letter of transmittal, you will represent to us that, among other things:

- any new notes that you receive will be acquired in the ordinary course of your business;
- you have no arrangement or understanding with any person or entity to participate in the distribution of the new notes;
- you are not our "affiliate," as defined in Rule 405 of the Securities Act; and
- if you are a broker-dealer that will receive new notes for your own account in exchange for old notes, you acquired those notes as a result of market-making activities or other trading activities and you will deliver a prospectus (or to the extent permitted by law, make available a prospectus) in connection with any resale of such new notes.

Withdrawal of Tenders

Except as otherwise provided in this prospectus, you may withdraw your tender at any time prior to 11:59 p.m., New York City time on the expiration date. For a withdrawal to be effective you must comply with the appropriate procedures of DTC's ATOP system. Any notice of withdrawal must specify the name and number of the account at DTC to be credited with withdrawn old notes and otherwise comply with the procedures of DTC.

We will determine all questions as to the validity, form, eligibility and time of receipt of notice of withdrawal. Our determination shall be final and binding on all parties. We will deem any old notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offer.

Any old notes that have been tendered for exchange but are not exchanged for any reason will be credited to an account maintained with DTC for the old notes. This crediting will take place as soon as practicable after withdrawal, rejection of tender or termination of the exchange offer. You may retender properly withdrawn old notes by following the procedures described under " Procedures for Tendering" above at any time prior to 11:59 p.m., New York City time, on the expiration date.

Fees and Expenses

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail; however, we may make additional solicitation by facsimile, telephone, electronic mail or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer-manager in connection with the exchange offer and will not make any payments to broker-dealers or others soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out-of-pocket expenses.

We will pay the cash expenses to be incurred in connection with the exchange offer. They include:

- all registration and filing fees and expenses;
- all fees and expenses of compliance with federal securities and state "blue sky" or securities laws;
- accounting fees, legal fees incurred by us, disbursements and printing, messenger and delivery services, and telephone costs; and

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related fees and expenses.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of old notes under the exchange offer. The tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if a transfer tax is imposed for any reason other than the exchange of old notes under the exchange offer.

Consequences of Failure to Exchange

If you do not exchange new notes for your old notes under the exchange offer, you will remain subject to the existing restrictions on transfer of the old notes. In general, you may not offer or sell the old notes unless the offer or sale is either registered under the Securities Act or exempt from the registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreements, we do not intend to register resales of the old notes under the Securities Act.

Accounting Treatment

We will record the new notes in our accounting records at the same carrying value as the old notes. This carrying value is the aggregate principal amount of the old notes adjusted for any bond discount or premium, as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with the exchange offer.

Other

Participation in the exchange offer is voluntary, and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered old notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any old notes that are not tendered in the exchange offer or to file a registration statement to permit resales of any untendered old notes.

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USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreements. We will not receive any proceeds from the issuance of the new notes in the exchange offer. In consideration for issuing the new notes as contemplated by this prospectus, we will receive old notes in a like principal amount. The form and terms of the new notes are identical in all respects to the form and terms of the old notes, except the new notes will be registered under the Securities Act and will not contain restrictions on transfer, registration rights or provisions for additional interest. Old notes surrendered in exchange for the new notes will be retired and cancelled and will not be reissued. Accordingly, the issuance of the new notes will not result in any change in our outstanding indebtedness.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table shows our selected historical consolidated financial data, for the periods and as of the dates indicated, for Antero Resources LLC and its subsidiaries. As of December 31, 2012, the subsidiaries of Antero Resources LLC included Antero Resources Appalachian Corporation and its wholly owned subsidiaries: Antero Resources Piceance LLC, Antero Resources Pipeline LLC, Antero Resources Arkoma LLC, Antero Resources Bluestone LLC, and Antero Resources Finance Corporation.

The selected statement of operations data for the years ended December 31, 2010, 2011 and 2012 and the balance sheet data as of December 31, 2011 and 2012 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected statement of operations data for the years ended December 31, 2008 and 2009 and the balance sheet data as of December 31, 2008, 2009, and 2010 are derived from our audited consolidated financial statements not included in this prospectus. The statement of operations data for all periods presented has been recast to present the results of operations from our Piceance Basin and Arkoma Basin operations in discontinued operations. The losses on the sales of these properties are also included in discontinued operations in 2012. The results from continuing operations reflect our remaining operations in the Appalachian Basin. No part of our general and administrative expenses or interest expense was allocated to discontinued operations. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included elsewhere in this prospectus.

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(in thousands, except ratios)	**Year Ended December 31, 2008**	**2009**	**2010**	**2011**	**2012**
Statement of operations data:					
Operating revenues:					
Natural gas sales	$	$ 2,252	$ 47,392	$ 195,116	$ 259,743
NGL sales					3,719
Oil sales			39	173	1,520
Realized gains on commodity derivative instruments			15,063	49,944	178,491
Unrealized gains on commodity derivative instruments		3,910	62,536	446,120	1,055
Gain on sale of assets					291,190
Total revenues		6,162	125,030	691,353	735,718
Operating expenses:					
Lease operating expenses		28	1,158	4,608	6,243
Gathering, compression and transportation		421	9,237	37,315	91,094
Production taxes		128	2,885	11,915	20,210
Exploration expenses		2,095	2,350	4,034	14,675
Impairment of unproved properties		100	6,076	4,664	12,070
Depletion, depreciation and amortization	391	1,706	18,522	55,716	102,026
Accretion of asset retirement obligations			11	76	101
Expenses related to acquisition of business			2,544		
General and administrative	16,171	20,843	21,952	33,342	45,284
Loss on sale of compression station				8,700	
Total operating expenses	16,562	25,321	64,735	160,370	291,703
Operating income (loss)	(16,562)	(19,159)	60,295	530,983	444,015
Other expense:					
Interest expense	$ (37,594)	$ (36,053)	(56,463)	$ (74,404)	(97,510)
Realized and unrealized losses on interest derivative instruments, net	(15,245)	(4,985)	(2,677)	(94)	
Total other expense	(52,839)	(41,038)	(59,140)	(74,498)	(97,510)
Income (loss) before income taxes	(69,401)	(60,197)	1,155	456,485	346,505
Income tax (expense) benefit	26,520		(939)	(185,297)	(121,229)
Income (loss) from continuing operations	(42,881)	(60,197)	216	271,188	225,276
Discontinued operations:					
Income (loss) from results of operations and sale of discontinued operations	126,837	(45,972)	228,412	121,490	(510,345)
Net income (loss) attributable to Antero equity owners	$ (83,956)	$ (106,169)	$ 228,628	$ 392,678	$ (285,069)

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(in thousands, except ratios)	**Year Ended December 31, 2008**	**2009**	**2010**	**2011**	**2012**
Balance sheet data (at period end):					
Cash and cash equivalents	$ 38,969	$ 10,669	$ 8,988	$ 3,343	18,989
Other current assets	165,199	84,175	147,917	330,299	255,617
Total current assets	204,168	94,844	156,905	333,642	274,606
Natural gas properties, at cost (successful efforts method):					
Unproved properties	649,605	596,694	737,358	834,255	1,243,237
Producing properties	1,148,306	1,340,827	1,762,206	2,497,306	1,689,132
Gathering systems and facilities	179,836	185,688	85,404	142,241	168,930
Other property and equipment	3,113	3,302	5,975	8,314	9,517
	1,980,860	2,126,511	2,590,943	3,482,116	3,110,816
Less accumulated depletion, depreciation, and amortization	(183,145)	(322,992)	(431,181)	(601,702)	(173,343)
Property and equipment, net	1,797,715	1,803,519	2,159,762	2,880,414	2,937,473
Other assets	27,084	38,203	169,620	574,744	406,714
Total assets	$ 2,028,967	1,936,566	$ 2,486,287	$ 3,788,800	$ 3,618,793
Current liabilities	$ 208,209	$ 112,493	$ 152,483	$ 255,058	376,296
Long-term indebtedness	622,734	515,499	652,632	1,317,330	1,444,058
Other long-term liabilities	20,469	9,467	86,185	257,606	124,702
Total equity	1,177,555	1,299,107	1,594,987	1,958,806	1,673,737
Total liabilities and equity	$ 2,028,967	$ 1,936,566	$ 2,486,287	$ 3,788,800	$ 3,618,793
Other financial data:					
EBITDAX(1)	$ 208,513	$ 201,270	$ 197,678	$ 340,821	$ 434,315
Net cash provided by operating activities	157,515	149,307	127,791	$ 266,307	332,255
Net cash used in investing activities	(1,004,010)	(281,899)	(230,672)	(901,249)	(463,491)
Net cash provided by financing activities	874,350	104,292	101,200	629,297	146,882
Capital expenditures(2)	1,041,748	203,454	423,002	929,887	1,755,430

(1) "EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense, realized and unrealized gains or losses on interest rate derivative instruments, taxes, impairments, depletion, depreciation, amortization, exploration expense, unrealized commodity hedge gains or losses, franchise taxes, stock compensation, business acquisition, gain or loss on sale of assets, and interest income. "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. 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. EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. EBITDAX does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes EBITDAX is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the natural gas and oil 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 a covenant under our Credit Facility. EBITDAX is also used as a measure of our operating performance pursuant to a covenant under the indentures governing our series of senior notes.

There are significant limitations to using 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 EBITDAX reported by different

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companies. The following table represents a reconciliation of our net income (loss) to EBITDAX (including continuing and discontinued operations) for the periods presented:

	Year Ended December 31,				
(in thousands)	**2008**	**2009**	**2010**	**2011**	**2012**
Net income (loss)	$ 83,956	$ (106,169)	$ 228,628	$ 392,678	$ (285,069)
Unrealized (gains) losses on commodity derivative contracts	(90,301)	61,186	(170,571)	(559,596)	44,753
(Gain) loss on sale of assets			(147,559)	8,700	504,755
Interest expense and other	52,839	41,038	59,140	74,498	97,510
Provision (benefit) for income taxes	3,029	(2,605)	30,009	230,452	(151,324)
Depreciation, depletion, amortization and accretion	124,997	140,078	134,272	170,956	191,251
Impairment of unproved properties	10,112	54,204	35,859	11,051	13,032
Exploration expense	22,998	10,228	24,794	9,876	15,339
Other	883	3,310	3,106	2,206	4,068
EBITDAX	$ 208,513	$ 201,270	$ 197,678	$ 340,821	$ 434,315

(2) Capital expenditures as shown in this table differ from the amounts shown in the statement of cash flows in the consolidated financial statements because amounts in this table include changes in accounts payable for capital expenditures from the previous reporting period while the amounts in the statement of cash flows in the financial statements are presented on a cash basis.

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RATIOS OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratios of earnings to fixed charges for the periods presented:

	Year Ended December 31,				
	2008	2009	2010	2011	2012
Ratio of earnings to fixed charges(1)	NA(2)	NA(2)	1.02X	7.11X	4.54X

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pretax income (loss) from continuing operations plus fixed charges. "Fixed charges" represents interest incurred, amortization of deferred debt offering costs and that portion of rental expense on operating leases deemed to be the equivalent of interest.

(2) We generated operating losses for each of the years ended December 31, 2008 and 2009. Accordingly, our earnings were inadequate to cover total fixed charges during such periods by approximately $69.4 million and $60.2 million, respectively.

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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 consolidated financial statements and related notes included elsewhere in this prospectus. In addition, such analysis should be read in conjunction with the historical audited financial statements and the related notes included elsewhere in this prospectus. 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 which could cause actual results to vary from our expectations include changes in natural gas, NGL, and oil prices, the timing of planned capital expenditures, 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 "Risk Factors" included elsewhere in this prospectus. We do not undertake any obligation to publicly update any forward-looking statements.

In this section, references to "Antero," "we," "us," "our" and "operating entities" refer to the subsidiaries that conduct Antero Resources LLC's operations, unless otherwise indicated or the context otherwise requires. For more information on our organizational structure, see "Business and Properties Corporate Sponsorship" or note 1 to the consolidated financial statements included elsewhere in this prospectus.

Our Company

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2012, we held approximately 371,000 net acres of rich gas and dry gas properties, which are 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 through internally generated projects on our acquired acreage. As of December 31, 2012, our estimated proved reserves were approximately 4.9 Tcfe, consisting of 3.7 Tcf of natural gas, 203 MMBbl of NGLs, and 3 MMBbl of oil. As of December 31, 2012, 75% of our proved reserves were natural gas, 21% were proved developed and 98% were operated by us. For the year ended December 31, 2012, we generated cash flow from operations of $332 million, a net loss of $285 million and EBITDAX of $434 million. The net loss in 2012 includes, (i) a pre-tax loss of $796 million on the sale of the Arkoma and Piceance Basin properties, (ii) deferred tax benefit related to the loss on the sale of the Arkoma and Piceance properties and discontinued operations of $273 million, (iii) a pre-tax gain on the sale of certain Appalachian gathering systems of $291 million, and (iv) a noncash tax provision related to continuing operations of $121 million. See "Selected Historical Consolidated Financial Data" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

We have assembled a diversified portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus, Utica and Upper Devonian Shales of the Appalachian Basin. From inception, we have drilled and operated 520 wells through December 31, 2012 with a success rate of approximately 98%. Our drilling inventory consists of approximately 4,900 potential well locations, all of which are unconventional resource opportunities. For information on the possible limitations on our ability to drill these potential locations, see "Risk Factors Risks Relating to Our Business Our identified potential well locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential well locations."

As of December 31, 2012, we had entered into hedging contracts covering a total of approximately 757 Bcfe of our projected natural gas and oil production from January 1, 2013 through December 31, 2018 at a weighted average index price of $4.88 per MMBtu. For the year ending December 31, 2013, we have hedged approximately 115 Bcfe of our projected natural gas and oil production at a weighted average index price of $4.93 per MMBtu. We believe this hedge position provides significant protection to future operations and capital spending plans.

Our current borrowing base under the Credit Facility is $1.22 billion and lender commitments are $700 million. Lender commitments under the facility can be expanded from $700 million to the full $1.22 billion borrowing base upon bank approval. The borrowing base under the Credit Facility is redetermined semi-annually and is based on the amount of our proved oil, NGL, and gas reserves and the estimated cash flows from these reserves and our hedge positions. The next redetermination is scheduled to occur in May 2013. The Credit Facility provides for a maximum availability of $2.5 billion. At December 31, 2012, we had $260 million of borrowings and letters of credit outstanding under the Credit Facility and $440 million of available borrowing capacity, based on $700 million of lender commitments at that date. Pro forma for the issuance of $225 million of 6.00% senior notes subsequent to year-end, we would have had $657 million of borrowing capacity at December 31, 2012. The Credit Facility matures in May 2016.

For the year ended December 31, 2012, our capital expenditures were approximately $1.69 billion for drilling, leasehold, and gathering. Our capital budget for 2013 is $1.65 billion, including $1.15 billion for drilling and completion, $350 million for the construction of gathering pipelines and facilities in the Appalachian Basin (including $150 million for water-handling infrastructure, primarily in the Marcellus Shale) and $150 million for leasehold. Our capital budget excludes acquisitions. Substantially all of the $1.15 billion allocated for drilling and completion is allocated to our operated drilling in rich gas areas. Approximately 87% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 13% is allocated to the Utica Shale. During 2013, we plan to operate an average of 12 drilling rigs in the Marcellus Shale and 2 drilling rigs in the Utica Shale. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results and commodity prices.

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

We operate in one industry segment, which is the exploration, development and production of natural gas, NGLs, and oil, and all of our operations are conducted in the United States. Our gathering assets are primarily dedicated to supporting the natural gas volumes we produce.

Source of Our Revenues

Our production revenues are entirely from the continental United States and during 2012 our revenues from both continuing and discontinued operations were comprised of approximately 85% from the production and sale of natural gas and 15% from the production and sale of NGLs and oil. Natural gas, NGL, and oil prices are inherently volatile and are influenced by many factors outside of our control. Our revenues are derived from the sale of natural gas and oil production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Substantially all of

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our production is derived from natural gas wells which also produce natural gas liquids and limited quantities of oil. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of our natural gas production. We currently use fixed price natural gas swaps in which we receive a fixed price for future production in exchange for a payment of the variable market price received at the time future production is sold. At the end of each period we estimate the fair value of these swaps and recognize an unrealized gain or loss. We have not elected hedge accounting and, accordingly, the unrealized gains and losses on open positions are reflected currently in earnings. We expect continued volatility in the fair value of these swaps.

Principal Components of Our Cost Structure

Lease operating expenses. These are the day to day operating costs incurred to maintain production of our natural gas, NGLs, and oil. Such costs include produced water disposal, pumping, maintenance, repairs, and workover expenses. Cost levels for these expenses can vary based on industry drilling and production activity levels and the resulting demand fluctuations for oilfield services.

Gathering, compression, and transportation. These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low pressure and high pressure gathering and compression systems as well as fees paid to third parties who operate low and high pressure gathering systems that transport our gas. It also includes costs to process and extract NGLs from our produced gas and to transport our NGLs and oil to market. Cost we incur for these expenses can vary based on industry drilling and production activity levels and the resulting demand fluctuations for oilfield services. We often enter in to fixed price long-term contracts that secure transportation and processing capacity that may include minimum volume commitments, the cost for which is included in these expenses.

Production taxes. Production taxes consist of severance and ad valorem taxes and are paid on produced natural gas, NGLs, and oil based on a percentage of market prices (not hedged prices) or at fixed per unit rates established by federal, state or local taxing authorities.

Exploration expense. These are geological and geophysical costs, including payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes and unsuccessful leasing efforts.

Impairment of unproved and proved properties. These costs include unproved property impairment and costs associated with lease expirations. We could record impairment charges for proved properties if the carrying value were to exceed estimated future cash flows. Through December 31, 2012, we have not recorded any impairment for proved properties.

Depreciation, depletion and amortization. This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs, and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate these costs to each unit of production using the units of production method.

General and administrative expense. These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance expenses.

Interest expense. We finance a portion of our working capital requirements and acquisitions with borrowings under our Credit Facility. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We also had at December 31, 2012 a fixed interest rate of 9.375% on senior notes having a principal balance of $525 million, a fixed interest rate of 7.25% on senior notes having a principal balance of

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$400 million, and a fixed interest rate of 6.00% on senior notes having a principal balance of $300 million. We expect to continue to incur significant interest expense as we continue to grow.

Income tax expense. Through December 31, 2011, each of our operating entities filed separate federal and state income tax returns; therefore, our provision for income taxes through that date consisted of the sum of our income tax provisions for each of the operating entities. In October 2012, the Company completed a reorganization of its legal structure by contributing all of the outstanding shares owned by Antero Resources LLC in each of the Antero Arkoma, Antero Piceance, and Antero Pipeline corporations to Antero Appalachian. Antero Arkoma, Antero Piceance, and Antero Pipeline were then converted to limited liability companies. As a result, for income tax purposes, the operations from the date of the reorganizations and tax attributes of Arkoma, Piceance and Pipeline are now combined with Antero Appalachian for tax reporting purposes. We are subject to state and federal income taxes but are currently not in a tax paying position for regular Federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC") and the deferral of unrealized commodity hedge gains for tax purposes until they are realized. We do pay some state income or franchise taxes where our IDC deductions do not exceed our taxable income or where state income or franchise taxes are determined on a basis other than income. We have generated net operating loss carryforwards which expire at various dates from 2024 through 2032. We have recognized the value of these net operating losses to the extent of our deferred tax liabilities. We recorded valuation allowances for deferred tax assets at December 31, 2012 of approximately $48 million primarily for capital loss and state loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or estimates of future taxable income are reduced.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives 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 December 31, 2012 of $15 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. No impact to the Company's 2012 effective tax rate would result from the recognition of the tax benefits. As of December 31, 2012, no interest or penalties have been accrued on unrecognized tax benefits. The Company had no unrecognized tax benefits at December 31, 2010 or 2011.

Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2012

The following table sets forth selected operating data (as recast for discontinued operations) for the year ended December 31, 2011 compared to the year ended December 31, 2012:

(in thousands, except per unit data)	Year Ended December 31, 2011	Year Ended December 31, 2012	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 195,116	$ 259,743	$ 64,627	33%
NGL sales		3,719	3,719	*
Oil sales	173	1,520	1,347	779%
Realized commodity derivative gains	49,944	178,491	128,547	257%
Unrealized commodity derivative gains	446,120	1,055	(445,065)	(100)%
Gain on sale of Appalachian gathering assets		291,190	291,190	*
Total operating revenues	691,353	735,718	44,365	6%

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(in thousands, except per unit data)	Year Ended December 31, 2011	2012	Amount of Increase (Decrease)	Percent Change
Operating expenses:				
Lease operating expenses	4,608	6,243	1,635	35%
Gathering, compression, and transportation	37,315	91,094	53,779	144%
Production taxes	11,915	20,210	8,295	70%
Exploration	4,034	14,675	10,641	264%
Impairment of unproved properties expense	4,664	12,070	7,406	159%
Depletion, depreciation and amortization	55,716	102,026	46,310	83%
Accretion of asset retirement obligations	76	101	25	33%
General and administrative expense	33,342	45,284	11,942	36%
Loss on sale of compressor station	8,700		(8,700)	*
Total operating expenses	160,370	291,703	131,333	82%
Operating income	530,983	444,015	(86,968)	(16)%
Other income expense:				
Interest expense	$ (74,404)	$ (97,510)	$ (23,106)	31%
Realized and unrealized interest rate derivative losses	(94)		94	*
Total other expense	(74,498)	(97,510)	(23,012)	31%
Income before income taxes	456,485	346,505	(109,980)	(24)%
Income taxes expense	(185,297)	(121,229)	(64,068)	(35)%
Income from continuing operations	271,188	225,276	(45,912)	(17)%
Income (loss) from discontinued operations	121,490	(510,345)	(631,835)	*
Net income (loss) attributable to Antero equity owners	$ 392,678	$ (285,069)	$ (677,747)	(173)%
EBITDAX(1)	$ 340,821	$ 434,312	$ 93,491	27%
Production data:				
Natural gas (Bcf)	45	87	42	93%
NGLs (MBbl)		71	71	*
Oil (MBbl)	2	19	17	963%
Combined (Bcfe)	45	87	42	93%
Daily combined production (MMcfe/d)	124	239	115	93%
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	$ 4.33	2.99	(1.34)	(31)%
NGLs (per Bbl)	$	52.07	52.07	*
Oil (per Bbl)	$ 97.19	80.34	(16.85)	(17)%
Combined (per Mcfe)	$ 4.33	3.03	(1.30)	(30)%
Average realized prices after-effects of hedges(2):				
Natural gas (per Mcf)	$ 5.44	5.05	(0.39)	(7)%
NGLs (per Bbl)	$	52.07	52.07	*
Oil (per Bbl)	$ 97.19	80.34	(16.85)	(17)%
Combined (per Mcfe)	$ 5.44	5.08	(0.36)	(7)%

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(in thousands, except per unit data)		Year Ended December 31, 2011	2012	Amount of Increase (Decrease)	Percent Change
Average costs (per Mcfe):					
Lease operating costs	$	0.10	0.07	(0.03)	(30)%
Gathering compression and transportation	$	0.83	1.04	0.21	25%
Production taxes	$	0.26	0.23	(0.03)	(12)%
Depletion depreciation amortization and accretion	$	1.24	1.17	(0.07)	(6)%
General and administrative	$	0.74	0.52	(0.22)	(30)%

(1) See "Selected Historical Consolidated Financial Data" included elsewhere in this prospectus for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

(2) Average prices shown in the table reflect both of the before-and-after-effects of our realized commodity hedging transactions. 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. Combined revenues from production of natural gas, NGLs, and oil increased from $195 million for the year ended December 31, 2011 to $265 million for the year ended December 31, 2012, an increase of $70 million, or 36%. Our production increased by 94% from 45 Bcfe in 2011 to 87 Bcfe in 2012. Increased production volumes increased revenues by $183 million, or 94%, (calculated as the increase in year-to-year volumes times the prior year average price), and combined commodity price decreases accounted for a $113 million, or 58% decrease in revenues (calculated as the decrease in year-to-year average combined price times current year production volumes).

Commodity hedging activities. 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 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 realized gains or losses on the derivative instruments, are recognized in our results of operations. The unrealized gains and losses represent the changes in the fair value of these swap agreements as the future strip prices fluctuate from the fixed price we will receive on future production. For the years ended December 31, 2011 and 2012, our hedges resulted in realized gains of $50 million and $178 million, respectively. For the years ended December 31, 2011 and 2012, our hedges resulted in unrealized gains of $446 million and $1 million, respectively. Unrealized gains in 2011 resulted from, (i) lower commodity prices at December 31, 2011 compared to December 31, 2010 for contracts outstanding at the end of both years and, (ii) from commodity prices at December 31, 2011 being lower than commodity swap prices for new contracts entered into in 2011. Additionally, prices did not vary significantly from year-end 2011 prices.

Gain on sale of Appalachian gathering assets. On March 26, 2012, we closed the sale of a portion of its Marcellus Shale gathering system assets along with exclusive rights to gather and compress the Company's gas for a 20-year period within an area of dedication ("AOD") to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together, "Crestwood") for $375 million (subject to customary purchase price adjustments). The sale included approximately 25

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miles of low pressure pipeline systems and gathering rights on 104,000 net acres held by the Company within a 250,000 acre AOD and had an effective date of January 1, 2012. Other third-party producers will also have access to the Crestwood system. During the first seven years of the contract, the Company is committed to deliver minimum volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies. We can earn up to an additional $40 million of sale proceeds if we meet certain volume thresholds over the first three years of the contract. Crestwood is obligated to incur all future capital costs to build out gathering systems and compression facilities within the AOD to connect the Company's wells as it executes its drilling program and has assumed the various risks and rewards of the system build-out and operations. Because we have not retained the substantial risks and rewards of ownership associated with the gathering rights and systems transferred to Crestwood, it has recognized a gain on the sale of the gathering system and gathering rights of approximately $291 million.

Lease operating expenses. Lease operating expenses increased from $5 million for the year ended December 31, 2011 to $6 million in 2012, primarily as a result of increased production. On a per-Mcfe basis, lease operating expenses decreased by 30%, from $0.10 per Mcfe in 2011 to $0.07 per Mcfe in 2012 primarily because of costs increasing at a lower rate than production. Because our Appalachian Basin properties are in a relatively early stage of production, lease operating expenses are minimal and are expected to increase as the properties mature.

Gathering, compression and transportation expense. Gathering, compression and transportation expense increased from $37 million for the year ended December 31, 2011 to $91 million in 2012. The increase in these expenses resulted from the increase in production, increased firm transportation commitments, and increases in third-party compression and gathering expenses as we move to outsource some of our compression and gathering activities. On a per-Mcfe basis, total gathering, compression, and transportation expenses increased from $0.83 per Mcfe for 2011 to $1.04 in 2012.

Production tax expense. Total production taxes increased from $12 million for the year ended December 31, 2011 to $20 million for the year ended December 31, 2012, primarily as a result of increased production. Production taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging were 6.1% for the year ended December 31, 2011 compared to 7.6% for the year ended December 31, 2012. West Virginia ad valorem taxes, which are based on the value of oil and gas reserves, accounted for the increase in the ratio of production tax expense to revenues as we increased our Appalachian reserves.

Exploration expense. Exploration expense increased from $4 million for the year ended December 31, 2011 to $15 million for the year ended December 31, 2012 primarily because of an increase in the cost of unsuccessful lease acquisition efforts.

Impairment of unproved properties. Impairment of unproved properties was approximately $5 million for the year ended December 31, 2011 compared to $12 million for the year ended December 31, 2012. The increase in impairment charges was due to an increase in expiring acreage and ongoing evaluation of our undeveloped Marcellus acreage. 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.

Depletion, depreciation and amortization ("DD&A"). DD&A increased from $56 million for the year ended December 31, 2011 to $102 million for the year ended December 31, 2012, an increase of $46 million, as a result of increased production in 2012 compared to 2011. DD&A per Mcfe decreased 6%, from $1.24 per Mcfe during 2011 to $1.17 per Mcfe during 2012 as a result of the increased proved reserves in 2012.

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We evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2011 or 2012 for proved properties. As of December 31, 2012, no significant exploratory well costs had been deferred for over one year pending proved reserves determination.

General and administrative expense. General and administrative expense increased from $33 million for the year ended December 31, 2011 to $45 million during 2012, an increase of $12 million. The increase is due to increased costs related to salaries, employee benefits, contract personnel and other general business expenses required to support the growth of our capital expenditure program and production levels. The number of our full-time employees grew from 107 at December 31, 2011 to 150 at December 31, 2012. On a per-Mcfe basis, general and administrative expense decreased by 30%, from $0.74 per Mcfe during the year ended December 31, 2011 to $0.52 per Mcfe during 2012 primarily due to a 94% growth in production. No portion of general and administrative expenses was allocated to discontinued operations as the Company does not expect any reduction of such expenses as a result of the sale of the Arkoma and Piceance properties. When all discontinued operations are included, general and administrative expenses were $0.37 per Mcfe for both 2011 and 2012.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased from $74 million for the year ended December 31, 2011 to $98 million for the year ended December 31, 2012, an increase of $24 million as a result of an increase in the amount of senior notes outstanding during 2012 compared to during 2011.

Income tax expense. For each tax year-end through December 31, 2011, Antero Resources LLC and each of its subsidiaries filed separate federal and state income tax returns. Antero Resources LLC is a partnership for income tax purposes and therefore is not subject to federal or state income taxes. The tax on the income of Antero Resources LLC is borne by its individual members through the allocation of taxable income. In October 2012, the Company completed a reorganization of its legal structure by contributing all of the outstanding shares owned by Antero Resources LLC in each of the Antero Arkoma, Antero Piceance, and Antero Pipeline corporations to Antero Appalachian. Antero Arkoma, Antero Piceance, and Antero Pipeline were then converted to limited liability companies. As a result, for income tax purposes, the operations from the date of the reorganizations and tax attributes of Arkoma, Piceance and Pipeline are now combined with Antero Appalachian for tax reporting purposes.

Income tax expense related to continuing operations was $121 million in 2012 compared to $185 million in 2011. Although we have accrued $15 million at December 31, 2012 for unrecognized tax benefits, no taxes are due at the end of either December 31, 2011 or 2012. We have not generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. At December 31, 2012, we had approximately $1.0 billion of U.S. Federal net operating loss carryforwards (NOLs) and approximately $1.3 billion of state NOLs, which expire starting in 2024 and through 2032. At December 31, 2012, we recorded valuation allowances of approximately $48 million for deferred tax assets primarily related to capital loss and state loss carryforwards. 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 the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that

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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 December 31, 2012 of $15 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. No impact to the Company's 2012 effective tax rate would result. As of December 31, 2012, no interest or penalties have been accrued on unrecognized tax benefits. The Company had no unrecognized tax benefits at December 31, 2010 or 2011.

Income (loss) from discontinued operations. Income (loss) from discontinued operations includes the results of operations from the Arkoma Basin and Piceance Basin operations (including revenues and direct operating expenses and allocated income tax expense, but not general and administrative or interest expenses) and, in 2012, the loss on the sale of these assets. A detailed analysis of these operations is included in note 3 to the consolidated financial statements included elsewhere in this prospectus. Income (loss) from discontinued operations decreased from income of $121 million in 2011 to a loss of $510 million in 2012, primarily as a result of the loss on the sale of the properties of $796 million and a $273 million tax benefit from the loss.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2011

The following table sets forth selected operating data (as recast for discontinued operations) for the year ended December 31, 2010 compared to the year ended December 31, 2011:

	Year Ended December 31,			
(in thousands, except per unit data)	**2010**	**2011**	**Amount of Increase (Decrease)**	**Percent Change**
Operating revenues:				
Natural gas sales	$ 47,392	$ 195,116	$ 147,724	312%
Oil sales	39	173	134	344%
Realized commodity derivative gains	15,063	49,944	34,881	232%
Unrealized commodity derivative gains	62,536	446,120	383,584	613%
Total operating revenues	125,030	691,353	566,323	453%
Operating expenses:				
Lease operating expenses	1,158	4,608	3,450	298%
Gathering, compression and transportation	9,237	37,315	28,078	304%
Production taxes	2,885	11,915	9,030	313%
Exploration expenses	2,350	4,034	1,684	72%
Impairment of unproved properties	6,076	4,664	(1,412)	(23)%
Depletion, depreciation and amortization	18,522	55,716	37,194	201%
Accretion of asset retirement obligations	11	76	65	591%
Expenses related to acquisition of business	2,544		(2,544)	*
General and administrative	21,952	33,342	11,390	52%
Loss on sale of compressor station		8,700	8,700	*
Total operating expenses	64,735	160,370	95,635	148%
Operating income	60,295	530,983	470,688	781%

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	Year Ended December 31,			
(in thousands, except per unit data)	**2010**	**2011**	**Amount of Increase (Decrease)**	**Percent Change**
Other expense:				
Interest expense	(56,463)	(74,404)	17,941	32%
Realized and unrealized interest rate derivative losses	(2,677)	(94)	(2,583)	(96)%
Total other expense	(59,140)	(74,498)	15,358	26%
Income before income taxes	1,155	456,485	455,330	*
Income tax expense	(939)	(185,297)	(184,358)	*
Income (loss) from continuing operations	216	271,188	270,972	*
Income from discontinued operations	228,412	121,490	(106,922)	(47)%
Net income attributable to Antero equity owners	$ 228,628	$ 392,678	$ 164,050	72%
EBITDAX(1)	$ 197,678	$ 340,821	$ 143,143	72%
Production data:				
Natural gas (Bcf)	11	45	34	317%
Oil (MBbl)		2	2	*
Combined (Bcfe)	11	45	34	317%
Daily combined production (MMcfe/d)	30	124	94	317%
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	$ 4.39	$ 4.33	$ (0.06)	(1)%
Oil (per Bbl)	$	$ 97.19	$ *	*
Combined (per Mcfe)	$ 4.39	$ 4.33	$ (0.06)	(1)%
Average realized prices after-effects of hedges(2):				
Natural gas (per Mcf)	$ 5.78	$ 5.44	$ (0.34)	(6)%
Oil (per Bbl)	$	$ 97.19	$ *	*
Combined (per Mcfe)	$ 5.78	$ 5.44	$ (0.34)	(6)%
Average costs (per Mcfe)(2):				
Lease operating costs	$ 0.11	$ 0.10	$ (0.01)	(9)%
Gathering, compression and transportation	$ 0.85	$ 0.83	$ (0.02)	(2)%
Production taxes	$ 0.27	$ 0.26	$ (0.01)	(4)%
Depletion, depreciation, amortization	$ 1.71	$ 1.24	$ (0.47)	(27)%
General and administrative	$ 2.03	$ 0.74	$ (1.29)	(64)%

(1) See "Selected Historical Consolidated Financial Data" included elsewhere in this prospectus for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

(2) Average prices shown in the table reflect both of the before-and-after effects of our realized commodity hedging transactions. 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. 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 $47 million for the year ended December 31, 2010 to $195 million for the year ended

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December 31, 2011, an increase of $148 million or 312%. Our production increased by 317% from 11 Bcfe in 2010 to 45 Bcfe in 2011. The net increase in revenues resulted from production volume increases reduced by commodity price decreases. Production increases accounted for a $150 million, or 317%, increase in revenues (calculated as the increase in year-to-year volumes times the prior year average price). Price decreases accounted for a $2 million, or 5%, decrease in revenues (calculated as the decrease in year-to-year average price times current year production volumes).

Commodity hedging activities. 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 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 realized gains or losses on the derivative instruments, are recognized in our results of operations. The unrealized gains and losses represent the changes in the fair value of these swap agreements as the future strip prices fluctuate from the fixed price we will receive on future production. For the years ended December 31, 2010 and 2011, our hedges resulted in realized gains of $15 million and $50 million, respectively. For the years ended December 31, 2010 and 2011, our hedges resulted in unrealized gains of $63 million and $446 million, respectively. The increase in unrealized gains from 2010 to 2011 resulted primarily from the decrease in natural gas prices.

Lease operating expenses. Lease operating expenses increased from $1 million for the year ended December 31, 2010 to $5 million in 2011, an increase of $4 million, as a result of a 317% increase in production.

Gathering, compression and transportation expense. Gathering, compression and transportation expense increased from $9 million for the year ended December 31, 2010 to $37 million in 2011 because of the increase in production and increased firm transportation commitments. On a per-Mcfe basis, these expenses decreased slightly from $0.85 per Mcfe for 2010 to $0.83 per Mcfe for 2011.

Production tax expense. Total production taxes increased from $3 million for the year ended December 31, 2010 to $12 million for the year ended December 31, 2011, as a result of increased production. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 6.1% in both years.

Exploration expense. Exploration expense increased from $3 million for the year ended December 31, 2010 to $4 million for the year ended December 31, 2011, primarily because of an increase in the cost of unsuccessful lease acquisition efforts.

Impairment of unproved properties. We abandon 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 short remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly. Our impairment of unproved property expense decreased from $6 million for the year ended December 31, 2010 to $5 million for the year ended December 31, 2011.

Depletion, depreciation and amortization (DD&A). DD&A increased from $19 million for the year ended December 31, 2010 to $56 million for the year ended December 31, 2011, an increase of $37 million as a result of increased production. DD&A per Mcfe decreased from $1.71 per Mcfe to $1.24 per Mcfe, primarily as a result of increased reserve volumes in 2011 compared to 2010. As a successful efforts company, we evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2010 or 2011 for proved properties. As of December 31, 2011, no significant well costs had been deferred for over one year pending proved reserves determination.

General and administrative expense. General and administrative expense increased from $22 million for the year ended December 31, 2010 to $33 million for 2011, an increase of $11 million. The increase is primarily due to increased costs related to salaries, employee benefits, contract personnel and professional services expenses for additional personnel required for our capital expenditure program and production levels. On a per-Mcfe basis, general and administrative expense decreased from $2.03 per Mcfe for the year ended December 31, 2010 to $0.74 per Mcfe for 2011. No portion of general and administrative expenses was allocated to discontinued operations as the Company does not expect any reduction of such expenses as a result of the sale of the Arkoma and Piceance properties. When all discontinued operations are included, general and administrative expenses decreased from $0.47 per Mcfe in 2010 to $0.37 per Mcfe in 2011.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased from $56 million for the year ended December 31, 2010 to $74 million for 2011, an increase of $18 million, primarily as a result of increased borrowings on the Credit Facility and the issuance of $400 million of 7.25% senior notes in August 2011. We had entered into variable-to-fixed interest rate swap agreements that hedged our exposure to interest rate variations on our Credit Facility and second lien term loan facility. At December 31, 2010, one of these swaps remained outstanding with a notional amount of $225.0 million and a fixed pay rate of 4.11%. This swap expired in July 2011. For the year ended December 31, 2010, we realized a loss on interest rate swap agreements of $10 million, whereas in 2011 we had a realized loss on interest rate swap agreements of $4 million. There were no outstanding interest swap agreements at December 31, 2011.

Income tax expense. Income tax expense related to continuing operations was $185 million in 2011 compared to $1 million in 2010 and is entirely comprised of deferred taxes in both years. In general, we have not generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. Each of our operating subsidiaries filed separate federal and state tax returns in 2010 and 2011; therefore, our provision for income taxes for those years consists of the sum of our provisions for each of the operating entities. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs and could significantly affect our future taxable position. The impact of any change will be recorded in the period that such legislation might be enacted.

Income from discontinued operations. Income from discontinued operations includes the results of operations from the Arkoma Basin and Piceance Basin operations (including revenues and direct operating expenses and allocated income tax expense, but not general and administrative or interest expenses). A detailed analysis of these operations is included in note 3 to the consolidated financial statements included elsewhere in this prospectus. Income from discontinued operations decreased from income of $228 million in 2010 to income of $121 million in 2011, primarily as a result of a nonrecurring gain of $148 million recognized in 2010 on the sale of our Arkoma midstream assets.

Capital Resources and Liquidity

Our primary sources of liquidity have been through issuances of debt securities, borrowings under our Credit Facility, asset sales, and net cash provided by operating activities. Our primary use of cash has been for the exploration, development and acquisition of natural gas, NGL, 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 expenditure activities and liquidity requirements. Our future success in growing proved reserves and

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production will be highly dependent on the capital resources available to us. We have approximately 4,900 potential well locations which will take many years to develop. Additionally our proved undeveloped reserves will require an estimated $3 billion of development capital over the next five years. A significant portion of this capital requirement will be funded out of operating cash flows. However, we may be required to generate or raise significant capital to conduct drilling activities on these potential drilling locations and to finance the development of our proved undeveloped reserves.

During 2012, we raised capital through the issuance of $300 million of 6.00% senior notes due 2020, and in February 2013 we issued another $225 million of the 6.00% senior notes. We also sold various properties for which we received cash proceeds of approximately $1.2 billion. As a result of the issuances of the 6.00% notes, the borrowing base under the Credit Facility is currently $1.22 billion and lender commitments total $700 million, leaving us with borrowing capacity of $657 million. At December 31, 2012, we had borrowed $217 million. Current lender commitments can be increased to the full $1.22 billion borrowing base upon approval of the lending bank group. The borrowing base is determined every six months based on reserves, oil and gas commodity prices, and the value of our hedge portfolio. The next redetermination of the borrowing base is scheduled to occur in May 2013. Our hedge position provides us with additional liquidity as it provides us with the relative certainty of receiving a significant portion of our future expected revenues from operations despite potential declines in the price of natural gas. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. Our Credit Facility is funded by a syndicate of 16 banks. We believe that the participants in the syndicate have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of our Credit Facility.

In order to fully fund our 2013 capital budget, we believe it will be necessary to obtain additional capital. We are considering several alternatives including increasing lender commitments on our Credit Facility, selling noncore gathering assets, or exploring further capital market transactions. We may pursue a combination of these alternatives. If necessary, we will revise our capital spending plans to our available cash flow from operations and other financing sources.

We believe that funds from operating cash flows and available borrowings under our Credit Facility will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months.

For more information on our outstanding indebtedness, see " Debt Agreements and Contractual Obligations."

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2010, 2011, and 2012:

	Year Ended December 31,		
	2010	2011	2012
		(in thousands)	
Net cash provided by operating activities	$ 127,791	$ 266,307	$ 332,255
Net cash used in investing activities	(230,672)	(901,249)	(463,491)
Net cash provided by financing activities	101,200	629,297	146,882
Net increase (decrease) in cash and cash equivalents	$ (1,681)	$ (5,645)	$ 15,646

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $128 million, $266 million and $332 million for the years ended December 31, 2010, 2011 and 2012, respectively. The increase in cash flows from operations from 2010 to 2011 and also from 2011 to 2012 was primarily the result of increased oil and gas production volumes and realized gains from commodity hedges, net of increased operating expenses and interest expense and changes in working capital.

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 prices. Prices for these commodities are determined primarily by prevailing market conditions. Factors including regional and worldwide economic activity, weather, infrastructure capacity to reach markets, and other variables 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 "Quantitative and Qualitative Disclosures About Market Risk."

Cash Flow Used in Investing Activities

During the years ended December 31, 2010, 2011 and 2012, we used cash flows in investing activities of $231 million, $901 million and $463 million, respectively, as a result of our capital expenditures for drilling, development and acquisitions. During 2012 we spent approximately $1.7 billion on investments in undeveloped leaseholds, development costs and gathering systems. Net cash flow used in investing activities was reduced by realized cash proceeds of approximately $1.2 billion from the sale of the Piceance Basin, Arkoma Basin, and certain Appalachian gathering systems. The increase in cash flows used in investing activities in 2011 from 2010 resulted primarily from increased drilling and acquisition activities in the Marcellus Shale. In September 2011, we also acquired a 7% overriding royalty interest related to 115,000 net acres operated by us in the core of our West Virginia and Pennsylvania Marcellus acreage position for $193 million.

Our board of directors has approved a capital budget of up to $1.65 billion for 2013. 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 in 2012 of $147 million was primarily the result of (i) $300 million of cash provided by the issuance of senior notes, net of (ii) net repayments of the Credit Facility of $148 million and other items of $5 million including deferred financing costs.

Net cash provided by financing activities in 2011 of $629 million was primarily the result of (i) $400 million of cash provided by the issuance of senior notes, (ii) net borrowings of $265 million on our Credit Facility, net of (iii) cash outflows for $7 million of deferred financing costs, and a $29 million distribution to equity members for tax liabilities.

Net cash provided by financing activities in 2010 of $101 million was primarily a result of (i) $156 million of cash provided by the issuance of senior notes, (ii) net payments of $42 million on our Credit Facility, and (iii) $13 million of other payment items including deferred financing costs.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility. Our Credit Facility provides for a maximum borrowing base of $1.22 billion. The borrowing base is redetermined semi-annually and the borrowing base depends on the amount of our proved oil and gas reserves and estimated cash flows from these reserves and our hedge positions. The next redetermination is scheduled to occur in May 2013. After giving effect to the issuance of the 6.00% senior notes due 2020 in November 2012 and February 2013, the borrowing base was $1.22 billion and lender commitments totaled $700 million. Lender commitments can be increased to the full $1.22 billion upon approval of the lending group. At December 31, 2012, we had $217 million of borrowings and $43 million of letters of credit outstanding under the Credit Facility. As a result of the sale of the Piceance properties, $11 million of letters of credit outstanding at December 31, 2012 were terminated in March 2013. The Credit Facility matures in May 2016.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the rate appearing on the Reuters BBA Libor Rates Page 3750 for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized. The amounts outstanding under the facility are secured by a first priority lien on substantially all of our natural gas, NGLs, and oil properties and associated assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. For information concerning the effect of changes in interest rates on interest payments under this facility, see "Quantitative and Qualitative Disclosures About Market Risk." As of December 31, 2011 and 2012, borrowings and letters of credit outstanding under our senior secured revolving credit facility totaled $386 million and $217 million, respectively, and had a weighted average interest rate (excluding the impact of our interest rate swaps) of 2.12% and 1.91%, respectively. The facility contains restrictive covenants that may limit our ability to, among other things:

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

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The Credit Facility also requires us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (as defined) 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, 2011 and 2012.

Senior Notes. We have $525 million of 9.375% senior notes outstanding, which are due December 1, 2017. The notes are issued by Antero Finance and unsecured and effectively subordinate to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after December 1, 2013 at redemption prices ranging from 104.688% on or after December 1, 2013 to 100.00% on or after December 1, 2015. In addition, on or before December 1, 2012, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 109.375%. At any time prior to December 1, 2013, Antero Finance may also redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium. If Antero Resources LLC undergoes a change of control, Antero Finance may be required to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

We also have $400 million of 7.25% senior notes outstanding, which are due August 1, 2019. The notes are issued by Antero Finance and unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes rank pari passu to the existing 9.375% senior notes. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on August 1 and February 1 of each year. Antero Finance may redeem all or part of the notes at any time on or after August 1, 2014 at redemption prices ranging from 105.438% on or after August 1, 2014 to 100.00% on or after August 1, 2017. In addition, on or before August 1, 2014, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 107.25% of the principal amount of the notes, plus accrued interest. At any time prior to August 1, 2014, Antero Finance may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If Antero Resources LLC undergoes a change of control, Antero Finance may be required to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

At December 31, 2012, we also had $300 million of 6.00% senior notes outstanding, which are due December 1, 2020. On February 4, 2013, we issued an additional $225 million of the 6.00% notes for an aggregate amount of $525 million. The notes are issued by Antero Finance and unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes rank pari passu to the existing 9.375% and 7.25% senior notes. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year, commencing on June 1, 2013. Antero Finance may redeem all or part of the 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

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or before December 1, 2015, Antero Finance may redeem up to 35% of the aggregate principal amount of the 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 notes, plus accrued interest. At any time prior to December 1, 2015, Antero Finance may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If a change of control (as defined in the bond indenture) occurs at any time prior to January 1, 2014, Antero Finance may, at its option, redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the notes, plus accrued interest. If Antero Finance has not exercised its optional redemption rights upon a change of control, the note holders will have the right to require Antero Finance to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under our Credit Facility 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 and the coverage ratio requirement as of December 31, 2011 and 2012.

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, 2013. At December 31, 2012, there were no outstanding borrowings under this facility.

Note Payable. We assumed a $25 million unsecured note payable in the Bluestone business acquisition consummated on December 1, 2010. The note has an outstanding balance of $25 million, bears interest at 9%, and is due December 1, 2013.

Contractual Obligations. A summary of our contractual obligations as of December 31, 2012 is provided in the following table.

(in millions)	2013	2014	2015	2016	2017	Thereafter	Total
Credit Facility(1)	$	$	$	$ 217	$	$	$ 217
Senior notes principal(2)	25				525	700	1,250
Senior notes interest(2)	99	96	96	96	96	112	595
Drilling rig and frac service commitments(3)	150	98	44				292
Firm transportation(4)	36	93	116	116	113	854	1,328
Gas processing, gathering, and compression service(5)	111	107	126	131	125	564	1,164
Office and equipment leases	1	3	3	3	3	15	28
Asset retirement obligations(6)						11	11
Total	$ 422	$ 397	$ 385	$ 563	862	$ 2,256	$ 4,885

(1) Includes outstanding principal amount at December 31, 2012. 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.

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(2) Includes the 9.375% senior notes due 2017, the 7.25% senior notes due 2019, and the 6.00% senior notes issued in November 2012 and due 2020, and the $25 million note due 2013 assumed in the Bluestone acquisition.

(3) At December 31, 2012, we had contracts for the services of 14 rigs, which expire at various dates from January 2013 through January 2016. We also had two frac services contracts, which expire in 2013 and 2014. 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 NGL 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 service 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) 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.

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. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See note 2 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Natural Gas, NGL and Oil Properties

Successful Efforts Method

Our natural gas, NGL, and oil exploration and production activities are accounted for using the successful efforts method. Under this method, costs of drilling successful exploration wells and development costs are capitalized and amortized on a geological reservoir basis using the

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unit-of-production method as natural gas, NGL, and oil is produced. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not discover proved reserves are expensed as exploration costs. The costs of development wells are capitalized whether productive or nonproductive. Natural gas, NGL, and oil lease acquisition costs are also capitalized. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unproved property costs are costs related to unevaluated properties and are transferred to proved natural gas and oil properties if the properties are determined to be productive. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unevaluated natural gas, NGL, and oil properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage. If it is determined that it is probable that reserves will not be discovered, the cost of unproved leases is charged to impairment of unproved properties. During the years ended December 31, 2010, 2011, and 2012 we charged impairment expense for expired or expiring leases with a cost of $36 million, $11 million, and $13 million, respectively. The assessment of unevaluated natural gas, NGL, and oil properties to determine any possible impairment requires managerial judgment.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. Additionally, the application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Natural Gas, NGL and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

Our independent engineers and internal technical staff prepare the estimates of natural gas, NGL, and oil reserves and associated future net cash flows. Current accounting guidance allows only proved natural gas, NGL, and oil reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of natural gas, NGL, and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our independent engineers and internal technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Natural gas, NGL, and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas, NGL, and oil that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, natural gas, NGL, and oil prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of natural gas, NGL, and oil that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

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Impairment of Proved Properties

We review our proved natural gas, NGL, and oil properties for impairment on a geological reservoir basis whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our gas and oil properties and compare these future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the natural gas, NGL, and oil properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded. We did not record any impairment charges for proved properties in 2010, 2011 or 2012.

Off-Balance Sheet Arrangements

We have various contractual obligations that are not reflected on our balance sheet. See "Debt Agreements and Contractual Obligations" included in this section for commitments under operating leases, drilling rig service agreements, firm transportation, and gas processing and compression service agreements.

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, NGL, and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Hedging Activities

Our primary market risk exposure is in the price we received 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, NGL, 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 prices, we have entered into financial commodity swap contracts to receive fixed prices for a portion of our natural gas, NGL, and oil production when management believes that favorable future prices can be secured. We typically hedge a fixed price for natural gas at our sales points (New York Mercantile Exchange ("NYMEX") less basis) to mitigate the risk of differentials to the Dominion South, Columbia Gas Appalachian Transmission ("CGTAP"), and Columbia Gas Louisiana ("CGLA") Indexes.

At December 31, 2012, we had in place natural gas and oil swaps covering portions of our projected production from 2013 through 2018. Our hedge position as of December 31, 2012 is

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summarized in note 12 to our consolidated financial statements included in this prospectus. Our financial hedging activities are intended to support natural gas, NGL, and oil prices at targeted levels and to manage our exposure to natural gas 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. 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 2018. Based on our annual production and our fixed price swap contracts in place during 2012, our annual income before taxes for the year ended December 31, 2012 would have decreased by approximately $2.0 million for each $0.10 decrease per MMBtu in natural gas prices and approximately $0.4 million for each $1.00 per barrel decrease in crude oil prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception, are recorded at fair market value in accordance with US GAAP and are included in the consolidated balance sheets as assets or liabilities. Fair values are adjusted for non-performance risk. As required under US GAAP, all 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 "Realized and unrealized gains (losses) on commodity derivative instruments." In 2012, approximately 81% of our production volumes were hedged, which resulted in realized hedge gains of $271 million. In 2011, approximately 77% of our production volumes were hedged, which resulted in realized hedge gains of $117 million. In 2010, approximately 79% of our production volumes were hedged, which resulted in realized gains on hedges of $74 million.

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 December 31, 2012, the estimated fair value of all of our commodity derivative instruments was a net asset of $532 million comprised of current and noncurrent assets. See note 12 to the consolidated financial statements included elsewhere in this prospectus for a summary of realized or unrealized gains or losses on commodity derivative contracts for 2010, 2011, and 2012.

By removing price volatility from a portion of our expected natural gas production through December 2018, 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.

Interest Rate Risks and Hedges

During the year ended December 31, 2012, we had indebtedness outstanding under our Credit Facility, which bears interest at floating rates. The average annual interest rate incurred on this indebtedness for the years ended December 31, 2011 and 2012 was approximately 2.1% during both years. A 1.0% increase in each of the average LIBOR rate and federal funds rate in 2012 would have resulted in an estimated $3 million increase in interest expense for the year ended December 31, 2012.

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At December 31, 2012, we had no interest rate swaps outstanding. From time to time in the past, we have entered into variable to fixed interest rate swap agreements which hedge our exposure to interest rate variations on our variable rate debt.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($532 million at December 31, 2012), joint interest receivables ($6 million at December 31, 2012) and the sale of our natural gas production ($47 million in receivables at December 31, 2012), which we market to energy marketing companies, refineries and affiliates.

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 cash, 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 but one are lenders in our Credit Facility. The fair value of our commodity derivative contracts of approximately $532 million at December 31, 2012 includes the following values by bank counterparty: JP Morgan $94 million; BNP Paribas $124 million; Credit Suisse $150 million; Wells Fargo $86 million; Barclays $57 million; Deutsche Bank $11 million; and Union Bank $4 million. Additionally, contracts with Dominion Field Services account for $6 million of the fair value. The credit ratings of certain of these banks were downgraded in 2011 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 at December 31, 2012 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. We are not required to provide credit support or collateral to any of our counterparties under current contracts, nor are they required to provide credit support to us. As of December 31, 2012, we have no past due receivables from or payables to any of our counterparties.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells.

We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. We 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.

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BUSINESS AND PROPERTIES

Our Company

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2012, we held approximately 371,000 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.

The following table provides a summary of selected operating data of our Appalachian Basin natural gas, NGL, and oil assets as of the date and for the period indicated.

	At December 31, 2012					Three months ended December 31, 2012
	Proved reserves (Bcfe)(1)	PV-10 (in millions)(2)	Net proved developed wells(3)	Total net acres(4)	Gross potential drilling locations(5)	Average net daily production (MMcfe/d)
Appalachian Basin:						
Marcellus Shale	4,796	$ 1,766	122	294,000	3,046	311
Upper Devonian	10	$ 9	2		1,250	4
Utica Shale	123	$ 148	2	77,000	627	1
Total	4,929	$ 1,923	126	371,000	4,923	316

(1) Estimated proved reserve volumes and values were calculated using the unweighted twelve-month average of the first-day-of-the-month reference prices for the period ended December 31, 2012, which were $2.78 per Mcf for natural gas, $19.61 per bbl for NGLs and $95.05 per bbl for oil.

(2) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to the standardized measure, please see "Our Operations Estimated Proved Reserves."

(3) Does not include 256 gross (224 net) shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions.

(4) Net acres allocable to the Upper Devonian are included in the net acres allocated to the Marcellus Shale because the Upper Devonian and the Marcellus Shale are multi-horizon shale formations attributable to the same leases.

(5) See "Risk Factors" for risks and uncertainties related to developing our potential well locations.

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. We have drilled and operated 520 wells from inception through December 31, 2012, with a success rate of approximately 98%. We have a multi-year drilling inventory and have approximately 4,900 potential well locations on our existing leasehold acreage, both proven and unproven.

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

We operate in one industry segment, which is the exploration, development and production of natural gas, NGLs, and oil, and all of our operations are conducted in the United States. Our gathering assets are primarily dedicated to supporting the natural gas volumes we produce.

2012 Developments and Highlights

Redeployment of Capital Resources to Appalachian Basin

We sold our Arkoma Basin assets in June 2012 and our Piceance Basin assets in December 2012 for total consideration of approximately $844 million of cash proceeds, which was used to pay down our borrowings under our senior secured revolving credit facility (our "Credit Facility"). Ultimately, the capital from the sales of these properties has been or will be invested in our Appalachian Basin properties in the Marcellus and Utica Shale plays, where we believe we can achieve more favorable risked rates of return than were obtained in the Arkoma and Piceance Basins. We are experiencing stronger well performance in the Appalachian Basin and better pricing because of the closer proximity of the Appalachian Basin to high density population centers and the related high demand for natural gas. Additionally, much of our projected Appalachian Basin production is liquids rich, high-BTU content gas that we expect will yield higher prices, particularly after the rich gas is processed to yield NGLs.

During 2012, we grew our Appalachian Basin proved reserves by 2,085 Bcfe, or 73%, and have replaced approximately the same quantity of reserves divested in 2012. During 2012, we drilled 64 horizontal wells in the Marcellus and Utica Shales, all of which were successful. We have also added significantly to our Appalachian Basin acreage position through the acquisition of approximately 157,000 acres during 2012, including a significant position in the Utica Shale play in Ohio. Our 2012 year-end acreage position in the Appalachian Basin was approximately 371,000 net acres, and we had a multi-year inventory of approximately 4,900 potential drilling locations in the Marcellus and Utica Shale plays at that date.

During 2012, we also sold a portion of our Marcellus Shale gathering system assets, along with exclusive rights to gather and compress our natural gas for a 20-year period within an area of dedication to a third-party midstream provider, for $376 million. We are committed to deliver minimum annual volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies. The third-party midstream provider is obligated to incur all future capital costs to build out gathering systems and compression facilities within the area of dedication. We reinvested the proceeds from the transaction into development drilling and land acquisition.

In connection with the redeployment of capital resources to the Appalachian Basin, we also streamlined our operating and capital structure by transferring the ownership of our Arkoma, Piceance, and Pipeline operating subsidiaries to Antero Resources Appalachian Corporation, which will be our primary employer and operating company going forward. We believe this simpler structure will provide both greater operating efficiencies and increased transparency to capital and credit markets as we finance our expanding capital budgets.

Our financial statements included elsewhere herein have been recast to show the results of the Arkoma Basin and Piceance Basin operations for all periods presented in discontinued operations.

Reserves, Production, and Financial Results

As of December 31, 2012, our estimated proved reserves were 4.9 Tcfe, consisting of 3.7 Tcf of natural gas, 203 MMBbl of NGLs and 3 MMBbl of oil. As of December 31, 2012, 75% of our

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estimated proved reserves by volume were natural gas and 21% were proved developed. From December 31, 2007 through December 31, 2012, we have increased our estimated proved reserves at a compounded annual growth rate of 84%, while our net production has increased over the three-year period ended December 31, 2012 at a compounded annual growth rate of 47% to an estimated 334 MMcfe/d in 2012 (including both continuing and discontinued operations). Our net production averaged an estimated 368 MMcfe/d in the fourth quarter of 2012 (including 47 MMcfe/d attributable to our Piceance Basin properties that were sold in mid-December 2012).

For the year ended December 31, 2012, we generated cash flow from operations of $332 million, a net loss of $285 million and EBITDAX of $434 million. The net loss in 2012 includes, (i) a pre-tax loss of $796 million on the sale of the Arkoma and Piceance Basin properties, (ii) deferred tax benefit related to the loss on the sale of the Arkoma and Piceance properties and discontinued operations of $273 million, (iii) a pre-tax gain on the sale of certain Appalachian gathering systems of $291 million, and (iv) a noncash tax provision related to continuing operations of $121 million. In contrast, for the year ended December 31, 2011, we generated cash flow from operations of $266 million, net income of $393 million, and EBITDAX of $341 million. See "Selected Historical Consolidated Financial Data" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

Hedge Position

As of December 31, 2012, we had entered into hedging contracts covering a total of approximately 757 Bcfe of our projected natural gas and oil production from January 1, 2013 through December 31, 2018 at a weighted average index price of $4.88 per MMBtu. For the year ending December 31, 2013, we have hedged approximately 115 Bcfe of our projected natural gas and oil production at a weighted average index price of $4.93 per MMBtu. We believe this hedge position provides us with protection to future cash flows to support our operations and capital spending plans for 2013.

Credit Facility Availability

Our current borrowing base under the Credit Facility is $1.22 billion and lender commitments are $700 million. Lender commitments under the Credit Facility can be expanded from $700 million to the full $1.22 billion borrowing base upon bank approval. The borrowing base under the Credit Facility is redetermined semi-annually and is based on the estimated future cash flows from our proved natural gas, NGL, and oil reserves and our hedge positions. The next redetermination is scheduled to occur in May 2013. The Credit Facility provides for a maximum availability of $2.5 billion. At December 31, 2012, we had $260 million of borrowings and letters of credit outstanding under the Credit Facility and $440 million of available borrowing capacity, based on $700 million of lender commitments at that date. Pro forma for the issuance of $225 million of 6.00% senior notes due 2020 subsequent to year-end, we would have had $657 million of available borrowing capacity at December 31, 2012. The Credit Facility matures in May 2016. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Debt Agreements and Contractual Obligations Senior Secured Revolving Credit Facility" for a description of the Credit Facility agreement.

Senior Notes Issuance

On November 19, 2012, we issued $300 million of 6.00% senior notes due December 2020 at par. On February 4, 2013, we issued an additional $225 million of the 6.00% senior notes at 103% of par. We used the proceeds to pay down amounts outstanding under the Credit Facility, for development of our properties, and for general corporate purposes.

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2012 Capital Spending and 2013 Capital Budget

For the year ended December 31, 2012, our capital expenditures were approximately $1.69 billion for drilling, leasehold, and gathering. Our capital budget for 2013 is $1.65 billion, including $1.15 billion for drilling and completion, $350 million for the construction of gathering pipelines and facilities in the Appalachian Basin (including $150 million for water-handling infrastructure, primarily in the Marcellus Shale) and $150 million for leasehold. We do not budget for acquisitions. Substantially all of the $1.15 billion allocated for drilling and completion is allocated to our operated drilling in rich gas areas. Approximately 87% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 13% is allocated to the Utica Shale. During 2013, we plan to operate an average of 12 drilling rigs in the Marcellus Shale and 2 drilling rigs in the Utica Shale. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Corporate Sponsorship

We began operations in 2004 and the Company, as it exists today, was formed in October 2009. We have funded our development and operating activities primarily through equity capital raised from private equity sponsors and institutional investors, issuance of debt securities, sales of non-core assets, borrowings under our bank credit facilities, and operating cash flows. Our primary private equity sponsors are affiliates of Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 1625 17th Street, Denver, Colorado 80202 and our telephone number is (303) 357-7310. Our website is located at http://www.anteroresources.com.

We make available our Annual Reports on Form 10-K and our Quarterly Reports on Form 10-Q. These documents are located on our website at http://www.anteroresources.com by selecting the "Investor Info" link and then selecting the "SEC Filings" link.

The above information is available to anyone who requests it and is free of charge either in print from our website or upon request by contacting Chad Green, Finance Director, using the contact information listed above. Information on our website is not incorporated into this prospectus or our other securities filings and is not a part of them.

Our Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared in accordance with the rules and regulations of the Securities and Exchange Commission (the "SEC").

Reserves Presentation

The following table summarizes our estimated proved reserves and related standardized measure and PV-10 at December 31, 2010, 2011 and 2012. Our estimated proved reserves as of December 31, 2012 are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent engineers, DeGolyer and MacNaughton ("D&M"). Our estimated proved reserves as of December 31, 2011 were based on evaluations prepared by our internal reserve engineers, which were audited by D&M and Ryder Scott & Company ("Ryder Scott"). Over 99% of our estimated proved reserves as of December 31, 2010 were prepared by D&M or Ryder Scott. We refer to these firms collectively as our independent engineers. Copies of the summary reports of D&M with respect to

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our reserves at December 31, 2012 are filed as Exhibits 99.1 and 99.2, respectively, to this prospectus. The information in the following table does not give any effect to or reflect our commodity hedges.

	At December 31,		
	2010	**2011**	**2012**
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	400	718	828
NGLs (MMBbl)	9	19	36
Oil (MMBbl)	1	2	1
Total equivalent proved developed reserves (Bcfe)	457	844	1,047
Proved undeveloped reserves:			
Natural gas (Bcf)	2,143	3,213	2,866
NGLs (MMBbl)	95	145	167
Oil (MMBbl)	9	15	2
Total equivalent proved undeveloped reserves (Bcfe)	2,774	4,173	3,882
Total estimated proved reserves (Bcfe)	3,231	5,017	4,929
Proved developed producing (Bcfe)	416	804	935
Proved developed non-producing (Bcfe)	41	40	112
Percent developed	14%	17%	21%
PV-10 (in millions)(1)	$ 1,466	$ 3,445	$ 1,923
Standardized measure (in millions)(1)	$ 1,097	$ 2,470	$ 1,601

(1) PV-10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax. For more information about the calculation of standardized measure, see footnote 16 to our consolidated financial statements included in elsewhere in this prospectus.

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The following table sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV-10), the present value of those net cash flows after income tax (standardized measure) and the prices used in projecting future net cash flows at December 31, 2010, 2011 and 2012:

	At December 31,		
(In millions, except per Mcf data)	**2010(1)**	**2011(2)**	**2012(3)**
Future net cash flows	$ 5,990	$ 11,470	$ 7,221
Present value of future net cash flows:			
Before income tax (PV-10)	$ 1,466	$ 3,445	$ 1,923
Income taxes	$ (369)	(975)	(322)
After income tax (Standardized measure)	$ 1,097	$ 2,470	$ 1,601

(1) 12-month average prices used at December 31, 2010 were $4.18 per Mcf for the Arkoma Basin, $3.93 per Mcf for the Piceance Basin and $4.51 per Mcf for the Appalachian Basin.

(2) 12-month average prices used at December 31, 2011 were $3.90 per Mcf for the Arkoma Basin, $3.84 per Mcf for the Piceance Basin and $4.16 per Mcf for the Appalachian Basin.

(3) 12-month average prices used at December 31, 2012 were $2.78 per Mcf for natural gas, $19.61 per bbl for NGLs, and $95.05 per bbl for oil (all reserves in Appalachian Basin).

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Prices for 2010, 2011, and 2012 were based on 12-month unweighted average of the first-day-of-the-month pricing, without escalation. Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Changes in Proved Reserves During 2012

The following table summarizes the changes in our estimated proved reserves during 2012 (in Bcfe):

Proved reserves, December 31, 2011	5,017
Extensions, discoveries, and other additions	1,951
Price and performance revisions	222
Sales of reserves in place(1)	(2,174)
Production	(87)
Proved reserves, December 31, 2012	4,929

(1) Includes 2012 production from Arkoma and Piceance Basins of 35 Bcfe.

Extensions, discoveries, and other additions during 2012 of 1,951 Bcfe were added through the drillbit in the Marcellus and Utica Shales, including the addition of 709 Bcfe attributable to NGLs and oil. Downward price revisions resulted in a reduction of proved reserves of 102 Bcfe and performance revisions increased proved reserves by 324 Bcfe. Sales of proved reserves of 2,174 Bcfe resulted from the sale of our Arkoma and Piceance Basin properties. Our estimated proved reserves as of December 31, 2012 totaled approximately 4.9 Tcfe. Our proved developed reserves increased year over year by 24% to 1,047 Bcfe at December 31, 2012.

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Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated proved undeveloped reserves during 2012 (in Bcfe):

Proved undeveloped reserves, December 31, 2011	4,173
Extensions, discoveries, and other additions	1,692
Price and performance revisions	(233)
Sales of reserves in place	(1,750)
Proved undeveloped reserves, December 31, 2012	3,882

Extensions, discoveries, and other additions during 2012 of 1,692 Bcfe proved undeveloped reserves were added through the drillbit in the Marcellus and Utica Shales, including the addition of 613 Bcfe attributable to NGLs and oil. Downward price revisions resulted in a reduction of proved undeveloped reserves by 95 Bcfe and performance revisions reduced proved undeveloped reserves by 138 Bcfe. Sales of proved undeveloped reserves of 1,750 Bcfe resulted from the sale of our Arkoma and Piceance Basin properties. Our estimated proved undeveloped reserves as of December 31, 2012 totaled approximately 3.9 Tcfe.

During the year ended December 31, 2012, we converted our beginning Appalachian Basin proved undeveloped reserves to proved developed reserves at a rate of 13%. The Company incurred costs of approximately $396 million in 2012 to develop proved undeveloped reserves. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2012 are approximately $3.3 billion over the next five years, which we expect to finance through cash flow from operations, borrowings under our Credit Facility, sales of non-core assets, and other sources of capital financing. Our drilling programs to date have focused on proving our undeveloped leasehold acreage through delineation drilling. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also focus on drilling our proved undeveloped reserves. All of our proved undeveloped reserves are expected to be developed over the next five years. See "Risk Factors Risks Relating to Our Business The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

Preparation of Reserve Estimates

Our proved reserve estimates as of December 31, 2012 included in this prospectus were prepared by our internal reserve engineers in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent engineers in their reserve auditing process. Periodically, our technical team meets with the independent engineers to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Our internally prepared reserve estimates and related reports are reviewed and approved by our Vice President of Reserves, Planning & Midstream, Ward McNeilly, and our Vice

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President of Production, Kevin J. Kilstrom. Mr. McNeilly has been with the Company since October 2010. Mr. McNeilly has 34 years of experience in oil and gas operations, reservoir management, and strategic planning. From 2007 to October 2010 Mr. McNeilly was the Operations Manager for BHP Billiton's Gulf of Mexico operations. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. From 1979 through 1996 Mr. McNeilly served in various domestic and international operations and reservoir and asset management positions with Amoco. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

Mr. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2007 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an Operations Manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999 where he served in various operating roles with a focus on unconventional resources. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University. Our senior management also reviews our reserve estimates and related reports with Mr. McNeilly and Mr. Kilstrom and other members of our technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves on a quarterly basis.

Proved reserves are those quantities of oil, natural gas, and NGLs which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, seismic data, and well test data.

Production, Revenues and Price History

Natural gas, NGLs, and oil are commodities; therefore, the price that we receive for our production is largely a function of market supply and demand. While demand for natural gas in the United States has increased dramatically since 2000, natural gas and NGL supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have been used to find and recover large amounts of oil and gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of gas reserves that may be economically produced and our ability to access capital markets. See "Risk Factors Risks Relating to Our Business Natural gas prices are volatile. A substantial or extended decline in natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

The following table sets forth information regarding our production, our revenues and realized prices, and production costs from continuing operations in the Appalachian Basin for the years ended

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December 31, 2010, 2011, and 2012. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Continuing Operations Data Appalachian Basin

	Year Ended December 31,		
	2010	2011	2012
Production data:			
Natural gas (Bcf):	11	45	87
NGLs (MBbl):			71
Oil (MBbl):		2	19
Total combined production (Bcfe)	11	45	87
Average daily combined production (MMcfe/d)	30	124	239
Gas and oil production revenues (in millions)	$ 47	$ 195	$ 265
Average prices:			
Natural gas (per Mcf)	$ 4.39	$ 4.33	$ 2.99
NGLs (per Bbl)	$	$	$ 52.09
Oil (per Bbl)	$	$ 97.19	$ 80.34
Combined average prices before effects of hedges (per Mcfe)(1)	$ 4.39	$ 4.33	$ 3.03
Combined realized prices after-effects of hedges (per Mcfe)(1)	$ 5.78	$ 5.44	$ 5.08
Average costs per Mcfe:			
Lease operating costs	$ 0.11	$ 0.10	$ 0.07
Gathering, compression and transportation	$ 0.85	$ 0.83	$ 1.04
Production taxes	$ 0.27	$ 0.26	$ 0.23
Depreciation, depletion, amortization and accretion	$ 1.71	$ 1.24	$ 1.17
General and administrative	$ 2.03	$ 0.74	$ 0.52

(1) Average prices shown reflect both of the before-and-after effects of our realized commodity hedging transactions. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges.

Discontinued Operations Data- Arkoma and Piceance Basins

The table above does not include the following production or revenue from discontinued operations from the Arkoma and Piceance Basin properties which were sold in 2012:

Production (combined Bcfe)	36	44	35
Gas, NGL and oil production revenues (in millions)	$ 159	$ 197	$ 125

See footnote 3 to the consolidated financial statements included elsewhere in this prospectus.

Productive Wells

As of December 31, 2012, we had a total of 381 gross (341 net) producing wells, averaging an 88% working interest. This well count includes 256 gross and 224 net shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions. Our wells are gas wells, many of which also produce oil, condensate and NGLs. We do not have interests in any wells that only produce oil or NGLs.

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Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2012. A majority of our developed acreage is subject to liens securing our Credit Facility. Approximately 55% of our Marcellus acreage and 23% of our Utica acreage is held by production. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

	Developed Acres		Undeveloped Acres		Total Acres	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Marcellus	20,078	19,740	366,376	274,035	386,454	293,775
Utica	1,645	1,272	91,963	75,540	93,608	76,812
Other			6,609	6,599	6,609	6,599
Total	21,723	21,012	464,948	356,174	486,671	377,186

Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of December 31, 2012 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such acreage is extended or renewed.

	Gross	Net
2013	16,618	10,023
2014	9,151	5,624
2015	30,374	19,408

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2010, 2011 and 2012. Gross wells reflect the sum of all wells in which we own an interest and includes historical drilling activity in the Appalachian, Arkoma, and Piceance Basins. Net wells reflect the sum of our working interests in gross wells.

	Year Ended December 31,					
	2010		**2011**		**2012**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:						
Productive	128	24	135	65	106	91
Dry						
Total development wells	128	24	135	65	106	91
Exploratory wells:						
Productive	56	22	74	30	22	17
Dry	11	5				
Total exploratory wells	67	27	74	30	22	17

Our Core Operating Area Appalachian Basin Marcellus and Utica Shales

Our properties in the Appalachian Basin are located in northern West Virginia, southeastern Ohio, and southeastern Pennsylvania. As of December 31, 2012, we had approximately 371,000 net leasehold

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acres in the Appalachian Basin containing rights to the Marcellus Shale and the Utica Shale, 48% of which was held by production. For the year ended December 31, 2012, we had 239 MMcfe/d of average net daily production from the Appalachian Basin.

As of December 31, 2012, we had a total of 381 gross (341 net) producing wells in the area. This well count includes 256 gross and 224 net shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions. From March 2009, when we drilled our first well in the Appalachian Basin, through December 31, 2012, we have completed a total of 125 gross (118 net) horizontal wells and 1 gross (1 net) vertical well in the area. We completed 64 gross (60 net) horizontal wells in 2012. We have an additional 40 gross (39 net) wells drilling or waiting on completion as of December 31, 2012. As of mid-March 2013, we have 13 drilling rigs operating in the Appalachian Basin. In addition to the 13 rigs, we employ 2 small drilling rigs to drill certain wells to the horizontal kickoff point. As of December 31, 2012, we had approximately 4,900 gross undrilled horizontal well locations in the basin.

In October 2012, the MarkWest operated Sherwood I facility, with an Antero contracted capacity of 200 MMcf/d, commenced operations in the Marcellus Shale. We have contracted for an additional 200 MMcf/d at the Sherwood II, processing plant, which is currently under construction and is expected to be operational in the second quarter of 2013. We have also contracted for 200 MMcf/d at the Sherwood III, processing plant, which is expected to be operational in the fourth quarter of 2013. We have a total of 550 MMcf/d of contracted capacity in the Sherwood I, II and III processing facilities. We have further committed to capacity in a fourth 200 MMcf/d processing plant, Sherwood IV, which could be operational during the second quarter of 2014, contingent on the timing of the final decision to install the fourth plant. In addition, we have contracted capacity at the Seneca I processing plant in the Utica Shale. The Seneca I processing plant will have a capacity of 200 MMcf/d and is expected to be operational in the fourth quarter of 2013. We will have a total of 150 MMcf/d of contracted capacity in the Seneca I processing facility. We expect to have 50 MMcf/d of interim processing capacity in MarkWest's Cadiz processing facility beginning late in the second quarter of 2013. We have secured 905,000 MMBtu/d of long-haul firm transportation or firm sales capacity with various entities, including 460,000 MMBtu/d of back-haul firm transportation to the Gulf Coast. We have also committed to 20,000 Bbl/d of ethane takeaway capacity on the Enterprise ATEX pipeline to Mont Belvieu, which we expect to go into service in early 2014. We continue to actively identify and evaluate additional processing and takeaway capacity to enhance the value of both our Marcellus and Utica Shale positions.

Gathering Systems

As of December 31, 2012, we owned and operated approximately 54 miles of gathering pipelines and two compressor stations in West Virginia and Pennsylvania to support our drilling activities in the Marcellus Shale play. During 2012, we sold 33 miles of gathering lines and entered into a contract with a third party to provide gas gathering and compression services for a significant part of our Marcellus Shale production. Eight additional compressor stations, which are owned and operated by third parties, are connected to the gathering systems and provide compression and dehydration services on a fixed fee basis. At year end 2012, we had approximately 28 miles of Antero-owned gathering lines and two compressor stations under construction to support our planned 2013 drilling activities.

Takeaway Capacity

We have contracted for firm transportation for approximately 564,000 MMBtu per day on the Columbia Gas Transmission Pipeline and 460,000 MMBtu per day on the Columbia Gulf Pipeline. The contracts begin from various dates from 2009 through November 1, 2014. Columbia Pipeline contracts for 10,000 MMBtu per day expire in 2013; the remainder of the commitments expire at various dates from 2017 through 2025. We also have firm transportation on the Equitrans pipeline for 50,000 MMBtu per day for a ten-year term, which began on August 1, 2012. We have firm transportation on the M3

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Appalachia Gathering system for 100 MMBtu per day beginning with the in-service date of the system (projected to be May 1, 2013). We also have 3,500 MMBtu per day of firm transportation capacity on the Dominion Transmission Gateway expansion project for a term of 10 years from the initial in-service date of September 2012. In addition to the firm transportation that we control, we also have term firm sales commitments to third parties who hold firm capacity on downstream interstate pipelines, or will utilize our firm transportation, for approximately 250,000 MMBtu per day. Of the 250,000 MMBtu per day of firm sales, 100,000 MMBtu per day utilizes our firm transportation capacity. In December 2011, we entered into an agreement for firm transportation of 20,000 Bbl/d of ethane on the Enterprise Products Partners L.P. ATEX pipeline from Appalachia to Mont Belvieu, Texas. The pipeline is expected to be in service in the first quarter of 2014.

We market the majority of the natural gas production from properties we operate for both our account and the account of the other working interest and royalty owners in these properties. We sell substantially all of our production to a variety of purchasers under short-term contracts or spot gas purchase contracts with terms ranging from one day to several months, all at market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business.

Based on the current demand for natural gas, NGLs, and oil and availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations. See "Note 2(o) Concentrations of Credit Risk" in our consolidated financial statements for the years ended December 31, 2010, 2011 and 2012 included elsewhere in this prospectus.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under natural gas leases; or
- net profits interests.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

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Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Regulation of the Natural Gas and Oil Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing natural gas and oil properties have statutory provisions regulating the exploration for and production of natural gas and oil, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC"), and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Natural Gas and Oil

The production of natural gas and oil is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

We own interests in properties located onshore in three U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the natural gas and oil industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act ("NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act ("NGA") and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

Beginning in 1992, FERC issued a series of orders to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an

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open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The Domenici Barton Energy Policy Act of 2005 ("EP Act of 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

On November 20, 2008, FERC issued Order 720, a final rule on the daily scheduled flow and capacity posting requirements. Under Order 720, major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtus of gas over the previous three calendar years, are required to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu per day and interstate pipelines are required to post information regarding the provision of no-notice service. In October 2011, Order 720, as clarified, was vacated by the Court of Appeals for the Fifth Circuit with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order 720, as clarified, remained applicable to interstate pipelines with respect to posting information regarding the provision of no-notice service.

We cannot accurately predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that

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might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act ("CEA") and regulations promulgated thereunder by the Commodity Futures Trading Commission ("CFTC"). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our natural gas and oil exploration and production operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences, restrict the types, quantities and concentrations of various substances that can be released

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into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits, establish specific safety and health criteria addressing worker protection and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act (the "NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an Environmental Assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study ("EIS") that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act ("RCRA"), and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by

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the U.S. Environmental Protection Agency ("EPA") or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that are regulated as hazardous wastes. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act(the "Clean Water Act"), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Obtaining permits has the potential to delay the development of natural gas and oil projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations, and further believe we are in substantial compliance with the terms thereof. We are currently undertaking a review of recently acquired natural gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction

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and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, on August 16, 2012, the EPA published final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic event; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations as does most of the domestic oil and gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to furthe