ANTERO RESOURCES CORP
Form 424B3
June 14, 2010

Use these links to rapidly review the document
TABLE OF CONTENTS
INDEX TO FINANCIAL STATEMENTS

Table of Contents

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PROSPECTUS

Offer to Exchange Up To $525,000,000 of 9.375% Senior Notes due 2017 That Have Not Been Registered Under The Securities Act of 1933 For Up To $525,000,000 of 9.375% Senior Notes due 2017 That Have Been Registered Under The Securities Act of 1933

Terms of the New 9.375% Senior Notes due 2017 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 17, 2009 and January 19, 2010, 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 5:00 p.m., New York City time, on July 14, 2010, 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Tenders of old notes may be withdrawn at any time prior to the expiration of the exchange offer.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 10 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 June 14, 2010

Table of Contents

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.

TABLE OF CONTENTS

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 $375 million principal amount of our 9.375% senior notes due 2017 issued on November 17, 2009, together with the additional $150 million principal amount of our 9.375% senior notes due 2017 issued on January 19, 2010, 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 has been formed to be the issuer of the notes. References to "Antero"

Table of Contents

or "Antero Resources" 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 Corporation, Antero Resources Midstream Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, each of which is a Delaware 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 and oil prices;
- timing and amount of future production of natural gas and oil;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- marketing of natural gas and oil;

leasehold or business acquisitions;

costs of developing our properties and conducting our gathering and other midstream operations;

Table of Contents

- general economic conditions;
- credit markets;
- liquidity and access to capital;
- 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 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 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.

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.

Table of Contents

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 10 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, 2007 and 2008 has been prepared by independent reserve engineering firms or by our internal reserve engineers, as applicable, in accordance with the rules and regulations of the SEC applicable to fiscal years ending before December 31, 2009. The information in this prospectus with respect to our estimated proved reserves as of December 31, 2009 has been prepared by our independent reserve engineering firms, in accordance with the rules and regulations of the SEC applicable to fiscal years ending on or after December 31, 2009. 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 production of natural gas properties located onshore in the United States. We focus on unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. 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 existing acreage. As of December 31, 2009, our estimated proved reserves were 1,140.7 Bcfe, consisting of 1,130.3 Bcf of natural gas and 1.7 MMBbl of oil and condensate. As of December 31, 2009, 99% of our proved reserves were natural gas, 24% were proved developed and 69% were operated by us. From December 31, 2006 through December 31, 2009, we grew our estimated proved reserves from 87.0 Bcfe to 1,140.7 Bcfe. In addition, we grew our average daily production from 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. For the year ended December 31, 2009 and the three months ended March 31, 2010, we generated cash flow from operations of $149.3 million and $52.0 million, respectively, net income (loss) of $(106.2) million and $87.6 million, respectively, and EBITDAX of $201.3 million and $51.7 million, respectively. See "Selected Historical Combined 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 a large inventory of repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus Shale of the Appalachian Basin, the Woodford Shale of the Arkoma Basin (the Arkoma Woodford), the Fayetteville Shale of the Arkoma Basin and the Mesaverde tight sands and Mancos Shale of the Piceance Basin. From inception, we have drilled and operated 285 wells through December 31, 2009 with a success rate of approximately 98%. Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. For information on the possible limitations on our ability to drill our potential locations, see "Risk Factors Risks Relating to Our Business Our identified drilling 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 drilling locations."

We own two midstream systems (one in the Arkoma Basin and one in the Piceance Basin), and 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 and foreseeable production.

Our board of directors has approved a capital expenditure budget of up to $366 million for 2010, approximately 89% of which is allocated to drilling. Of our 2010 drilling budget, approximately 43% is allocated to the Appalachian Basin, 29% to the Arkoma Basin Woodford Shale and 28% to the Piceance Basin. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget based on liquidity, commodity prices and drilling results.

We believe we have a conservative financial position characterized by modest leverage, a strong hedge position and ample liquidity. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending December 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. On November 17, 2009, we completed an offering of $375 million principal amount of our 9.375% senior notes due 2017. On January 19, 2010, we completed an offering of $150 million additional principal amount of our 9.375% senior notes due 2017. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility.

Corporate Sponsorship and Structure

We began operations in 2004, and have funded development and operating activities of each of the operating subsidiaries primarily through equity capital raised from private equity sponsors and institutional investors, through borrowings under our bank credit facilities and through internal operating cash flows. Our primary private equity sponsors are affiliates of Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners.

Antero Resources LLC was formed as a holding company in October 2009 in connection with our corporate reorganization of the operating subsidiaries and the issuance of a new class of units in Antero in November 2009. Prior to this reorganization, all of our operations were conducted by five separately capitalized commonly controlled operating subsidiaries.

In connection with the November 2009 corporate reorganization, the stockholders of each of the operating subsidiaries contributed all of the outstanding shares of each operating subsidiary to Antero. In return, Antero issued an equivalent number of units of different classes to such stockholders. The newly issued units are substantially similar in character to the contributed stock of each operating subsidiary, including the relative priority of any distributions made by Antero as well as the vesting schedule applicable to shares held by any member of management. Simultaneously with this exchange, Antero issued a new class of units in exchange for $110 million in new equity capital. Later in November 2009, Antero issued additional units of such new class in exchange for an additional $15 million in new equity capital. We refer to these issuances in this prospectus as our November 2009 equity placements. None of Antero's outstanding units are entitled to current cash distributions or are convertible into indebtedness, and Antero has no obligation to repurchase these units at the election of the unitholders.

Table of Contents

We used the aggregate net proceeds of approximately $124 million from the November 2009 equity placements to repay borrowings outstanding under our senior secured revolving credit facility.

Antero Resources Finance Corporation, the issuer of the notes, was formed in October 2009 as an indirect wholly owned subsidiary of Antero. The issuer was formed to arrange financing for Antero and the operating subsidiaries, including the notes. The indenture governing the notes limits the issuer's activity to those of a finance subsidiary. The issuer does not own any significant assets other than intercompany obligations. The five operating subsidiaries together own all of the outstanding common stock of the issuer. Antero owns all of the outstanding common stock of the five operating subsidiaries.

For more information on our corporate restructuring and the November 2009 equity placements, see "Business Corporate Sponsorship and Structure."

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.

Table of Contents

The Exchange Offer

On November 17, 2009, we completed a private offering of $375 million principal amount of the old notes. On January 19, 2010, we completed a private offering of an additional $150 million principal amount of the old notes. We entered into registration rights agreements with the initial purchasers in connection with these offerings in which we agreed to deliver to you this prospectus and to use commercially reasonable efforts to complete the exchange offer within 360 days after the date of the initial issuance of the old notes (November 17, 2009).

Exchange Offer	We are offering to exchange new notes for old notes.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on July 14, 2010, 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 5:00 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."

Table of Contents

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 5:00 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."
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 our 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 Wells Fargo Bank, N.A.,

Table of Contents

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.

Table of Contents

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 9.375% senior notes due 2017.
Maturity	December 1, 2017.
Interest Payment Dates	Interest on the notes will be paid semi-annually in arrears on June 1 and December 1 and of each year commencing on June 1, 2010. 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. As of March 31, 2010, the only non-guarantor subsidiary of Antero, Centrahoma Processing LLC (which is 60% owned by Antero), had no outstanding indebtedness and held less than 4% of our consolidated total assets. 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); 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.

Table of Contents

	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 indebtedness under the guarantors' senior secured revolving credit facility and capital leases, to the extent of the value of the collateral securing such indebtedness. As of March 31, 2010, the notes and the guarantees ranked effectively junior to approximately $11 million of senior secured indebtedness (letters of credit) outstanding under our senior secured revolving credit facility and approximately $1 million under capital leases.
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, 2013, 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 the date of such redemption. At any time prior to December 1, 2013, 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 the date of such redemption. In addition, on or prior to December 1, 2012, the issuer may, at any time or 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 109.375% of the principal amount of the notes, plus any accrued and unpaid interest to 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 purchase all or a portion of the new notes at a price equal to 101% of the aggregate principal amount of the notes, together with any accrued and unpaid interest to 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 the date of purchase.
Certain Covenants	The issuer will issue the new notes under an indenture, dated as of November 17, 2009, with Wells Fargo Bank, National Association, as trustee. The indenture, among other things, limits the ability of Antero and its restricted subsidiaries to: incur, assume or guarantee additional indebtedness or issue preferred stock; pay dividends on equity securities, repurchase equity securities or redeem subordinated indebtedness;

Table of Contents

	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."
Transfer Restrictions; 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 10 for a discussion of certain factors you should consider in evaluating whether or not to tender your old notes.

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 mentioned in the preceding paragraph, 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 Notes

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 our 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.

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. In particular, the cost of raising money in the debt and equity capital markets has increased substantially over the last 18 months, while the availability of funds from those markets has diminished significantly. Also, as a result of concern about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide funding to borrowers.

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

Table of Contents

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 senior secured revolving credit facility and the indenture governing the 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.

On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million. Our next scheduled borrowing base redetermination is expected to occur in October 2010. In the future, we may not be able to access adequate funding under our senior secured revolving 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 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 the notes.

If we are unable to comply with the restrictions and covenants in the agreements governing our 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 indenture governing the notes or in our senior secured revolving 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 senior secured revolving credit facility, 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 senior secured revolving credit facility), 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 senior secured revolving 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.

Table of Contents

If our operating performance declines, in the future we may need to obtain waivers from the requisite number of lenders under our senior secured revolving credit facility to avoid being in default. If we breach our covenants under our senior secured revolving 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 senior secured revolving 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 senior secured revolving credit facility, to the extent of the value of the collateral securing the indebtedness. The notes and the guarantees are also effectively subordinated to any indebtedness of any non-guarantor subsidiaries.

If we were unable to repay indebtedness under our senior secured revolving 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.

We may be able to 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 and in other instruments governing our other outstanding indebtedness (including our senior secured revolving credit facility), we may incur substantial additional indebtedness (including secured indebtedness) in the future. Although the indenture governing the notes and the instruments governing our senior secured revolving credit facility contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial.

If the issuer or any guarantor incurs any additional indebtedness that ranks equally with the notes (or with the guarantee 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 March 31, 2010, we had total long-term indebtedness of approximately $529 million.

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;
- 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 by.

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.

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

Our senior secured revolving credit facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness). Our senior secured revolving 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;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The indenture governing the notes contains similar restrictive covenants. In addition, our senior secured revolving 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 indenture governing 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 indenture governing the notes and our senior secured revolving credit facility impose on us.

Our senior secured revolving 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 senior secured revolving 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 senior secured revolving credit facility. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million. Our next scheduled borrowing base redetermination is expected to occur in October 2010.

A breach of any covenant in our senior secured revolving 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 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 Capital Resources and Liquidity Cash Flow Provided by Financing Activities 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 five operating subsidiaries guarantee the issuer's obligations under the notes. Unless they guarantee the notes, neither Centrahoma Processing LLC nor any of our future subsidiaries will 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 indenture governing the notes limits 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 waiver and certain qualifications and exceptions.

Your ability to transfer the notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will 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. The initial purchasers are not obligated, however, to make a market in the old notes or the new notes and any market making may be discontinued at any time at their sole discretion. No assurance can be given as to the liquidity of or trading market for the old notes or the new notes.

The liquidity of any trading market for the notes and the market prices quoted for the notes depend upon the number of holders of the notes, the overall market for high yield securities, our financial performance or prospects or the prospects for companies in our industry generally, the interest of securities dealers in making a market in the notes and other factors.

Table of Contents

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

Under the terms of the indenture governing the notes, you may require us to repurchase all or a portion of your 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). Our existing and any future credit facilities or other debt agreements to which we become a party may provide that our obligation to repurchase the notes would be an event of default under such agreement. As a result, we may be restricted or prohibited from repurchasing the notes. If we are prohibited from repurchasing the notes, we could seek the consent of our then-existing lenders to repurchase the notes or we could attempt to refinance the borrowings that contain such prohibition. If we are unable to obtain any such consent or refinance such borrowings, we would not be able to repurchase the notes. Our failure to repurchase tendered notes would constitute a default under the indenture governing the notes and might constitute a default under the terms of our existing or future indebtedness.

In a recent decision, the Chancery Court of the State of Delaware raised the possibility that a change of control put right occurring as a result of a failure to have "continuing directors" comprising a majority of a board of directors may be unenforceable on public policy grounds.

The term "change of control" is limited to certain specified transactions and may not include other events that might adversely affect our financial condition. Our obligation to repurchase the notes upon a change of control would not necessarily afford holders of notes protection in the event of a highly leveraged transaction, reorganization, merger or similar transaction.

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 initial guarantors of the notes. In certain circumstances, any of Antero's future subsidiaries may be required to guarantee the notes. A court 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 into:

- 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 could void or subordinate the guarantees in favor of the guarantor's other obligations.

A legal challenge of a guarantee on fraudulent conveyance grounds may focus, among other things, on the benefits, if any, the guarantor realized as a result of our issuing the notes. To the extent a guarantee is voided as a fraudulent conveyance or held unenforceable for any other reason, the holders of the notes would not have any claim against that guarantor and would be creditors solely of the issuer and any other guarantors whose guarantees are not held unenforceable.

Table of Contents

The measures of insolvency for purposes of fraudulent transfer laws vary depending upon the governing law. Generally, a guarantor would be considered 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.

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

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

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 the current conflicts in the Middle East and conditions in 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;

Table of Contents

- 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 current worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets has lead to a worldwide economic recession. The slowdown in economic activity caused by such recession has reduced worldwide demand for energy and resulted in lower natural gas prices. Natural gas spot prices have recently been particularly volatile and declined from record high levels in early July 2008 of over $13.00 per Mcf to below $4.00 per Mcf in September 2009.

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. Lower natural gas prices may also reduce the amount of natural gas that we can produce economically.

Substantial decreases in natural gas prices would render uneconomic a significant portion of our exploration, development and exploitation projects. 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 $282 million in 2009. Our capital expenditure budget for 2010 is $366 million, with approximately $326 million allocated for drilling and completion operations. We expect to fund these capital expenditures with cash generated by operations and through borrowings under our senior secured revolving credit facility. 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 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 senior secured revolving 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;

Table of Contents

- 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 senior secured revolving 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 senior secured revolving 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 these 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;
- equipment failures or accidents;
- adverse weather conditions, such as blizzards and ice storms;
- declines in natural gas prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for natural gas.

18

Table of Contents

Our estimates of proved reserves at December 31, 2009 have been prepared under new SEC rules that went into effect for fiscal years ending on or after December 31, 2009. The new SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

This prospectus includes estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under the SEC's new rules relating to the reporting of oil and natural gas exploration activities. These new rules are effective for fiscal years ending on or after December 31, 2009, and require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down any proved undeveloped reserves that are not developed within the required five-year timeframe.

The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this prospectus have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these 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. See "Business Our Operations Estimated Proved Reserves" for information about our estimated natural gas and oil reserves and the PV-10 and standardized measure of discounted future net cash flows.

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 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.

Table of Contents

Our identified drilling 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 drilling locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling 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 drilling 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 drilling 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 16,000 potential drilling locations. As a result of the limitations described above, we may be unable to drill many of our potential resource play drilling 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.

In addition, the acquisition agreement relating to the purchase of our properties in the Appalachian Basin in 2008 contains various drilling commitments that may require us to spend up to an estimated $625 million between January 1, 2009 and June 30, 2018 at structured intervals. If we do not fulfill our drilling commitments, title to portions of the properties we purchased may revert to the seller, which could have a material adverse effect on our future business and results of operations.

If commodity prices decrease, 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 write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our natural gas 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.

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.

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 173 Bcf of our natural gas production from April 1, 2010 through December 2014. We are currently realizing a significant benefit from these hedge positions. For example, for the year ended December 31, 2009, we received approximately $116.5 million 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 2014. 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. For additional information regarding our hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Commodity Hedging Activities."

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 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 March 31, 2010, our receivables from our derivatives counterparties were approximately $139.9 million. Any default by these counterparties on their obligations to us would have a material adverse effect on our financial condition and results of operations.

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.

Table of Contents

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 ($4.9 million at March 31, 2010) and the sale of our natural gas production ($22.6 million in receivables at March 31, 2010), 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, 2009 purchased approximately 44% 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.

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 flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater 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 losses to us as a result of:

- 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.

Table of Contents

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 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.

Table of Contents

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 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. For example, Congress is currently considering legislation that, if adopted in its proposed form, would subject companies involved in natural gas and oil exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of certain U.S. federal tax incentives and deductions available to natural gas exploration and production companies, and the prohibition or additional regulation of private energy commodity derivative and hedging activities. These and other 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.

See "Business Regulation of the Natural Gas and Oil Industry" for a further description of the laws and regulations that affect us.

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

We may incur significant delays, costs and liabilities as a result of environmental, 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, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement polices that have tended to become increasingly strict over time. 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. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. 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.

New laws, regulations or enforcement policies could 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.

See "Business Regulation of Environmental and Occupational Matters" for a further description of the laws and regulations that affect us.

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.

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

Table of Contents

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.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" (GHGs) and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere and other climatic changes. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of GHGs. One bill approved by the U.S. House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, or ACESA, would require an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050. Similar bills are presently pending before the U.S. Senate. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved.

In addition, in December 2009, the U.S. Environmental Protection Agency, or the EPA, determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule became effective in March 2010 but it does not require immediate reductions in GHG emissions. The stationary source rule was adopted in May 2010 but it does not become effective until January 2011 and is the subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress currently is considering broad financial regulatory reform legislation that among other things would impose comprehensive regulation on the over-the-counter (OTC) derivatives marketplace and could affect the use of derivatives in hedging transactions. The financial regulatory reform bill adopted by the House of Representatives on December 11, 2009, would subject swap dealers and "major swap participants" to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants. For these purposes, a major swap participant generally would be someone other than a dealer who maintains a "substantial" net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the U.S. banking system or financial markets. The House-passed bill also would provide the Commodity Futures Trading Commission (CFTC) with express authority to impose position limits for OTC derivatives related to energy commodities. Separately, in late January, 2010, the CFTC proposed regulations that would impose speculative position limits for certain futures and option contracts in natural gas, crude oil, heating oil, and gasoline. These proposed regulations would make an exemption available for certain *bona fide* hedging of commercial risks. On May 20, 2010, the Senate adopted its version of financial reform legislation. The Senate-passed bill would permit a "commercial end user" of certain derivatives to elect out of central clearing if it is using the derivative to hedge its own commercial risk, in which case new margin requirements also would not apply. House-Senate conferees must reconcile the two versions of the legislation, including the provisions applicable to derivatives, prior to final passage. Although it is not possible at this time to predict the final form the legislation will take, any laws or regulations that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recent Colorado legislative changes could limit our Piceance Basin operations and adversely affect our cost of doing business.

Our future Piceance Basin operations and cost of doing business may be affected by changes in regulations and the ability to obtain drilling permits. Our properties located in the Piceance Basin are subject to the authority of the Colorado Oil and Gas Conservation Commission, or COGCC. The COGCC has the authority to regulate natural gas and oil activities to protect public health, safety and welfare, including the environment and wildlife. In 2007, the Colorado state legislature approved legislation requiring the COGCC to promulgate rules (1) in consultation with the Colorado Department of Public Health and Environment, or CDPHE, to provide CDPHE an opportunity to provide comments on public health issues during the COGCC's decision-making process and (2) in consultation with the Colorado Division of Wildlife, or CDOW, to establish standards for minimizing adverse impacts to wildlife resources affected by natural gas and oil operations and to ensure the proper reclamation of wildlife habitat during and following such operations. These rules became effective April 1, 2009 for the majority of our Piceance Basin operations. We believe the revised rules will cause additional costs and may cause delay in our operations in Colorado. The rules require consultation with the CDOW and CDPHE prior to drilling and completion operations in our Piceance Basin project area. These rules are open-ended and resulting permit restrictions remain subject to appeal by the CDOW, CDPHE and the surface owner. The rules also would impact the ability and extend the time necessary to obtain drilling permits, which creates substantial uncertainty about our ability to obtain sufficient permits in a timely fashion in order to meet future drilling plans and thus production and capital expenditure targets. It is also possible that similar rules will be proposed in the other states in which we operate, further impacting our operations.

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.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A significant portion of our business activities is conducted through joint operating agreements under which we own partial interests in natural gas properties. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells that we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Seasonal weather conditions and lease stipulations 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 lease stipulations designed to protect various wildlife. In certain areas of Colorado, for example, drilling and other natural gas activities can only be conducted during the spring and summer months. 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, 2009, outstanding borrowings under our senior secured revolving credit facility were approximately $142 million, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased annual interest expense of approximately $1.4 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. 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 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 senior secured revolving credit facility imposes and the indenture governing the notes will impose certain limitations on our ability to enter into mergers or combination transactions. Our senior secured revolving credit facility and the indenture governing the notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

The obligations associated with being an SEC reporting company will require significant resources and management attention, which could have a material adverse effect on our business and operating results.

Following the effectiveness of the registration statement of which this prospectus forms a part, we will become subject to certain of the reporting requirements of the Exchange Act and the Sarbanes-Oxley Act of 2002, or the Sarbanes-Oxley Act. Under the Exchange Act, we will be required to file annual, quarterly and current reports with respect to our business and financial condition. Under the Sarbanes-Oxley Act, we will be required to, among other things, establish and maintain effective internal controls and procedures for financial reporting. As a result, we may incur significant additional legal, accounting and other expenses that we have not previously incurred. We anticipate that we may need to upgrade our systems, implement additional financial and management controls, reporting systems and procedures, implement an internal audit function, and hire additional accounting and internal audit staff. Furthermore, the need to establish the corporate infrastructure demanded of a reporting company may divert management's attention from implementing our growth strategy, which could prevent us from improving our business, results of operations and financial condition. We have made, and will continue to make, changes to our internal controls and procedures for financial reporting and accounting systems to meet our reporting obligations as a stand-alone public company. However, the measures we take may not be sufficient to satisfy our obligations as a public company. In addition, we cannot predict or estimate the amount of additional costs we may incur in order to comply

Table of Contents

with these requirements. We anticipate that these costs will materially increase our general and administrative expenses.

Section 404 of the Sarbanes-Oxley Act requires annual management assessments of the effectiveness of our internal control over financial reporting, starting with the annual report that we would expect to file with the SEC for the year ending December 31, 2011, and will require in such annual report, a report by our independent registered public accounting firm on the effectiveness of our internal control over financial reporting. In connection with the implementation of the necessary procedures and practices related to internal control over financial reporting, we may identify additional deficiencies. We may not be able to remediate any future deficiencies in time to meet the deadline imposed by the Sarbanes-Oxley Act for compliance with the requirements of Section 404. In addition, failure to achieve and maintain an effective internal control environment could have a material adverse effect on our business.

Risks Relating to Taxes

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to natural gas and oil exploration and development are eliminated as a result of future legislation.

President Obama's proposed budget for fiscal year 2010 contains a proposal to eliminate certain key U.S. federal income tax preferences currently available to natural gas and oil exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for natural gas and oil 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, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. The Oil Industry Tax Break Repeal Act of 2009, which was introduced in the Senate on April 23, 2009, includes many of the same proposals.

It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal, the Senate bill or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to natural gas and oil exploration and development. Any such change could negatively impact our financial condition and results of operations by increasing the costs we incur which would in turn make it uneconomic to drill some prospects if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

Recently proposed severance taxes in Pennsylvania could materially increase our liabilities.

A portion of our acreage in the Marcellus Shale in the Appalachian Basin is located in the State of Pennsylvania. Pennsylvania has historically not imposed a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. However, as a result of a focus on the state budget deficit and the increasing exploitation of the Marcellus Shale, the Pennsylvania state legislature is currently considering a proposed severance tax on natural gas drilling. If such legislation is adopted, these taxes may materially increase our operating costs in Pennsylvania.

EXCHANGE OFFER

Purpose and Effect of the Exchange Offer

At each closing of the offerings 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 360th day following the date of the initial issuance of the notes (November 17, 2009).

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 17, 2009. 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.

Table of Contents

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 " Procedures for Tendering 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 360th day following the date of the initial issuance of the notes (November 17, 2009), 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 360th calendar day following the date of the initial issuance of the notes (November 17, 2009), 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 rendered 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.

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 5:00 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 connecting 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 5:00 p.m., New York City time, on July 14, 2010, 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.

Table of Contents

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 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 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.

Table of Contents

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

Table of Contents

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 5:00 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 5:00 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

related fees and expenses.

Table of Contents

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.

Table of Contents

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.

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. The subsidiaries of Antero Resources LLC include Antero Resources Corporation, Antero Resources Midstream Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation, Antero Resources Appalachian Corporation (collectively referred to as the "Antero Entities" or the "operating entities"), and Antero Finance Corporation. Prior to the formation of Antero Resources LLC in 2009, the Antero Entities were under common control, as the ownership interests in each entity were held by the same individual stockholders in the same percentages. In 2009, the ownership interests in each of the Antero Entities were contributed to a newly formed limited liability company, Antero Resources LLC, resulting in each entity being a wholly owned subsidiary of Antero Resources LLC. The assets and liabilities of the Antero Entities were carried forward at their historical basis. The selected statement of operations data for the year ended December 31, 2007, 2008 and 2009 and the balance sheet data as of December 31, 2008 and 2009 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, 2005 and 2006 and the balance sheet data as of December 31, 2005, 2006 and 2007 are derived from our audited combined financial statements not included in this prospectus. The selected statement of operations data for the three months ended March 31, 2009 and 2010 and balance sheet data as of March 31, 2010 are derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The selected balance sheet data as of March 31, 2009 has been derived from our unaudited and unreviewed consolidated financial statements not included in this prospectus. The selected unaudited consolidated financial data has been prepared on a consistent basis with our audited consolidated financial statements. In the opinion of management, such selected unaudited consolidated financial data reflects all adjustments (consisting of normal and recurring accruals) considered necessary to present our financial position for the periods presented. The results of operations for the interim periods are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received from natural gas and oil, natural production declines, the uncertainty of exploration and development drilling results and other factors. 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

Table of Contents

Results of Operations" and our consolidated financial statements and related notes included elsewhere in this prospectus.

(in thousands, except ratios)	Year Ended December 31, 2005	2006	2007	2008	2009	Three Months Ended March 31, 2009	2010
Statement of operations data:							
Operating revenues:							
Natural gas sales	$ 14,526	$ 14,271	$ 63,975	$ 220,219	$ 123,915	$ 37,332	$ 53,952
Oil sales	195	523	3,749	9,496	5,706	1,063	2,114
Realized and unrealized gains (losses) on commodity derivative instruments	(13,148)	14,331	18,992	116,354	55,364	38,686	111,083
Gathering and processing revenue	294	717	4,778	20,421	23,005	4,379	6,413
Total revenues	1,867	29,842	91,494	366,490	207,990	81,460	173,562
Operating expenses:							
Lease operating expenses	808	1,189	4,435	13,350	17,606	6,945	4,598
Gathering, compression and transportation	920	2,482	10,016	29,033	28,190	6,375	10,141
Production taxes	445	1,012	2,233	10,281	4,940	1,832	2,670
Exploration expense	5,455	8,832	17,970	22,998	10,228	2,429	1,352
Impairment of unproved properties	30,000	8,117	4,995	10,112	54,204	7,767	2,262
Depletion, depreciation and amortization	6,526	7,940	50,091	124,821	139,813	39,701	32,996
Accretion of asset retirement obligations		9	68	176	265	62	73
General and administrative	3,755	7,478	11,682	16,171	20,843	4,406	4,412
Total operating expenses	47,909	37,059	101,490	226,942	276,089	69,517	58,504
Operating income (loss)	(46,042)	(7,217)	(9,996)	139,548	(68,099)	11,943	115,058
Other income (expense):							
Interest expense	(592)	(1,366)	(25,124)	(37,594)	(36,053)	(7,178)	(13,292)
Realized and unrealized gains (losses) on interest derivative instruments, net			(3,033)	(15,245)	(4,985)	(1,375)	(1,602)
Total other expense	(592)	(1,366)	(28,157)	(52,839)	(41,038)	(8,553)	(14,894)
Income (loss) before income taxes	(46,634)	(8,583)	(38,153)	86,709	(109,137)	3,390	100,164
Income tax (expense) benefit		(400)	400	(3,029)	2,605	1,605	(11,318)
Net income (loss)	(46,634)	(8,983)	(37,753)	83,680	(106,532)	4,995	88,846
Noncontrolling interest in net loss of consolidated subsidiary				276	363	159	(1,241)
Net income (loss) attributable to Antero equity owners	$ (46,634)	$ (8,983)	$ (37,753)	$ 83,956	$ (106,169)	$ 5,154	$ 87,605

Table of Contents

(in thousands, except ratios)	Year Ended December 31, 2005	2006	2007	2008	2009	Three Months Ended March 31, 2009	2010
Balance sheet data (at period end):							
Cash and cash equivalents	$	$ 1,945	$ 11,114	$ 38,969	$ 10,669	$	$ 6,314
Other current assets	57,502	35,036	64,145	165,199	84,175	152,020	125,943
Total current assets	57,502	36,981	75,259	204,168	94,844	152,020	132,257
Natural gas properties, at cost (successful efforts method):							
Unproved properties	41,186	61,307	201,210	649,605	596,694	645,033	600,233
Producing properties	15,841	208,127	617,697	1,148,306	1,340,827	1,205,485	1,407,126
Gathering systems and facilities		40,247	133,917	179,836	185,688	181,470	188,506
Other property and equipment	1,004	1,068	1,440	3,113	3,302	3,154	3,474
	58,031	310,749	954,264	1,980,860	2,126,511	2,035,142	2,199,339
Less accumulated depletion, depreciation, and amortization	(325)	(8,208)	(58,299)	(183,145)	(322,992)	(222,854)	(355,995)
Property and equipment, net	57,706	302,541	895,965	1,797,715	1,803,519	1,812,288	1,843,344
Other assets	207	920	8,058	27,084	38,203	29,630	100,297
Total assets	$ 115,415	$ 340,442	$ 979,282	$ 2,028,967	$ 1,936,566	$ 1,993,938	$ 2,075,898
Current liabilities	$ 25,346	$ 78,258	$ 165,091	$ 208,209	$ 112,493	$ 156,749	$ 138,612
Long-term indebtedness	13,500	83,897	415,659	622,734	515,499	532,702	529,304
Other long-term liabilities	113	859	4,230	20,469	9,467	15,629	20,029
Total equity	76,456	177,428	394,302	1,177,555	1,299,107	1,288,858	1,387,953
Total liabilities and equity	$ 115,415	$ 340,442	$ 979,282	$ 2,028,967	$ 1,936,566	$ 1,993,938	$ 2,075,898
Other financial data:							
EBITDAX(1)	$ 3,475	$ (629)	$ 59,980	$ 208,513	$ 201,270	$ 57,329	$ 51,725
Net cash provided by (used in) operating activities	(12,227)	(18,101)	24,745	157,515	$ 149,307	$ 66,640	51,989
Net cash used in investing	(41,523)	(158,265)	(600,902)	(1,004,010)	(281,899)	(115,321)	(65,989)
Net cash provided by financing activities	53,750	178,311	585,326	874,350	104,292	9,712	9,645
Capital expenditures(2)	61,425	367,019	646,469	1,041,748	203,454	65,939	75,390
Ratio of EBITDAX to interest expense	4.13x	(3)	2.39x	5.55x	5.58x	7.99x	3.89x

(1) "EBITDAX" is a non-GAAP financial measure that we define as net income 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 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,

Table of Contents

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 senior secured revolving credit facility. EBITDAX is also used as a measure of our operating performance pursuant to a covenant under the indenture governing the 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 companies. The following table represents a reconciliation of our net income to EBITDAX for the periods presented:

	Year Ended December 31,					Three Months Ended March 31,	
(in thousands)	**2005**	**2006**	**2007**	**2008**	**2009**	**2009**	**2010**
Net income (loss)	$ (46,634)	$ (8,983)	$ (37,753)	$ 83,956	$ (106,169)	$ 5,154	$ 87,605
Unrealized (gains) losses on commodity derivative contracts	7,371	(18,656)	(4,619)	(90,301)	61,186	(5,114)	(98,812)
Interest expense and other	841	1,366	28,157	52,839	41,038	8,553	14,894
Provision (benefit) for income taxes		400	(400)	3,029	(2,605)	(1,605)	11,318
Depreciation, depletion, amortization and accretion	6,526	7,949	50,159	124,997	140,078	39,763	33,069
Impairment of unproved properties	30,000	8,117	4,995	10,112	54,204	7,767	2,262
Exploration expense	5,455	8,832	17,970	22,998	10,228	2,429	1,352
Other	(84)	346	1,471	883	3,310	382	37
EBITDAX	$ 3,475	$ (629)	$ 59,980	$ 208,513	$ 201,270	$ 57,329	$ 51,725

(2) Capital expenditures as shown in this table differ from the amounts shown in the statement of cash flows in the 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.

(3) Our EBITDAX was insufficient to cover our interest expense for this period by approximately $2.0 million.

Table of Contents

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,						Three Months Ended March 31,
	2005	2006	2007	2008	2009	Pro forma 2009	2010
Ratio of earnings to fixed charges(1)	(2)	(2)	(2)	3.30x	(2)	(1)	8.50x

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pretax income (loss) 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. Because the net proceeds of the November 2009 and January 2010 offerings of the old notes were used to repay indebtedness, pro forma impact on the amount of fixed charges causes our deficiency in earnings to cover fixed charges to change by 10% or more for the year ended December 31, 2009. Because the old notes and related interest were included in our financial results for most of the three months ended March 31, 2010, the pro forma impact on the amount of fixed charges did not cause our ratio of earnings to fixed charges to change by more than 10% for that period. After giving effect to the application of the net proceeds of the November 2009 and January 2010 offerings of the old notes, including the application of the net proceeds therefrom to repay borrowings under our senior secured revolving credit facility as if such transactions had occurred at the beginning of 2009 (which borrowings repaid under our senior secured revolving credit facility may be reborrowed from time to time, including for general corporate purposes and to fund our capital expenditure program), our pro forma earnings would have been inadequate to cover fixed charges for the year ended December 31, 2009 by approximately $129.3 million. This pro forma data does not give effect to the application of the net proceeds of our November 2009 $125 million equity placements. At December 31, 2009, we had approximately $142.1 million of borrowings outstanding under our senior secured revolving credit facility. The average interest rate paid on amounts outstanding under our senior secured revolving credit facility for the year ended December 31, 2009 was 4.2% (excluding the impact of our interest rate swaps).

(2) We generated operating losses for each of the years ended December 31, 2005, 2006, 2007 and 2009. Accordingly, our earnings were inadequate to cover total fixed charges during such periods by approximately $46.6 million, $8.6 million, $38.2 million and $109.1 million, respectively.

Table of Contents

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 combined financial statements and related notes appearing 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 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 and elsewhere in this prospectus, 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." In this section, references to "Antero," "we," "us," "our" and "operating entities" refer to the five corporations referred to as the operating entities in the other portions of this prospectus (Antero Resources Corporation, Antero Resources Midstream Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation), unless otherwise indicated or the context otherwise requires.

Overview

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and production of natural gas properties located onshore in the United States. We focus on unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. 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 existing acreage. As of December 31, 2009, our estimated proved reserves were 1,140.7 Bcfe, consisting of 1,130.3 Bcf of natural gas and 1.7 MMBbl of oil and condensate. As of December 31, 2009, 99% of our proved reserves were natural gas, 24% were proved developed and 69% were operated by us. From December 31, 2006 through December 31, 2009, we grew our estimated proved reserves from 87.0 Bcfe to 1,140.7 Bcfe. In addition, we grew our average daily production from 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. For the years ended December 31, 2008 and 2009, we generated cash flow from operations of $157.5 million and $149.3 million, respectively, net income (loss) of $84.0 million and $(106.2) million, respectively, and EBITDAX of $208.5 million and $201.3 million, respectively. For the three months ended March 31, 2010, we generated cash flow from operations of $52.0 million, net income of $87.6 million and EBITDAX of $51.7 million. See "Selected Historical Combined 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 a large inventory of repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus Shale of the Appalachian Basin, the Woodford Shale of the Arkoma Basin (the Arkoma Woodford), the Fayetteville Shale of the Arkoma Basin and the Mesaverde tight sands and Mancos Shale of the Piceance Basin. From inception, we have drilled and

Table of Contents

operated 285 wells through December 31, 2009 with a success rate of approximately 98%. Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. For information on the possible limitations on our ability to drill our potential locations, see "Risk Factors Risks Relating to Our Business Our identified drilling 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 drilling locations."

We own two midstream systems in the Arkoma and Piceance Basins, and 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 and foreseeable production.

For the year ended December 31, 2009, we spent approximately $203.5 million on capital expenditures, approximately 89% of which is allocated to low-risk development projects with the remaining capital budget allocated to infrastructure projects and land acquisition. Our board of directors has approved a capital expenditure budget of up to $366 million for 2010, approximately 89% of which is allocated to drilling. Of our 2010 drilling budget, approximately 43% is allocated to the Appalachian Basin, 29% to the Arkoma Basin Woodford Shale and 28% to the Piceance Basin. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget based on liquidity, commodity prices and drilling results.

We believe we have a conservative financial position characterized by modest leverage, a strong hedge position and ample liquidity. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending December 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. On November 17, 2009, we completed an offering of $375 million principal amount of our 9.375% senior notes due 2017. On January 19, 2010, we completed an offering of $150 million additional principal amount of our 9.375% senior notes due 2017. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility.

We operate in one industry segment, which is the exploration, development and production of natural gas and oil, and all of our operations are conducted in the United States. Our gathering and processing 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 currently is comprised of 95% natural gas and 5% oil. Gas prices reached historically high levels in recent years and reached over $13.00 per Mcf in July 2008. Since then, natural gas prices have declined sharply to approximately $4.00 per Mcf in April 2010. Natural gas and oil prices are inherently volatile and are influenced by many factors outside of our control. 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. For example, for the year ended December 31, 2009, we received approximately $116.5 million in cash flows pursuant to our hedges. At each period end 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. During the years ended December 31, 2007, 2008 and 2009, we recognized significant unrealized commodity gains on these swaps as market prices were lower than our fixed price swaps. We expect continued volatility in the fair value of these swaps. We do not enter into derivatives to manage volatility for our oil or NGL sales.

Principal Components of Our Cost Structure

Lease operating and gathering, compression and transportation expenses. These are daily costs incurred to bring natural gas and oil out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our natural gas and oil properties. These costs stabilized in 2009 and are expected to remain moderate in the first half of 2010.

Production taxes. Production taxes consist of severance and ad valorem taxes and are paid on produced natural gas and oil based on a percentage of market prices (not hedged prices) or at fixed 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 also record impairment charges for proved properties if the carrying value were to exceed estimated future cash flows. Through December 31, 2009, it has not been necessary to record 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 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 are included in general and administrative expenses.

Interest expense. We finance a portion of our working capital requirements and acquisitions with borrowings under our bank credit facilities. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We also have fixed interest at 9.375% on the new notes having a principal balance of $525 million. We will likely continue to incur significant interest expense as we continue to grow. We have also entered into various variable to fixed interest rate swaps to mitigate the effects of interest rate changes. We do not designate these swaps as hedges and therefore do not accord them hedge accounting treatment. Realized and unrealized gains or losses on these interest rate derivative instruments are included as a separate line item in other income (expense).

Income tax expense. Each of the operating entities files separate federal and state income tax returns; therefore, our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. 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"). 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 another basis. Collectively, the operating entities have generated net operating loss carryforwards which expire starting in 2024 through 2029. We have not recognized the full value of these net operating losses on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit equal to the full amount of the loss carryforward over time. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or

Table of Contents

estimates of future taxable income are reduced. We have recognized deferred tax expense for certain subsidiaries that have deferred tax liabilities in excess of their deferred tax assets due to unrealized gains on derivative instruments and basis differences in assets.

Significant Acquisitions

The following table presents a summary of our significant proved and unproved property acquisitions in 2007 and 2008. There were no significant acquisitions in 2009.

Primary locations of acquired properties	Date acquired	Purchase price (in millions)
Arkoma Basin Woodford Shale (OK)	December 2007	$ 61.0
Piceance Basin (CO)	July 2008	$ 39.2
Appalachian Basin (PA, WV)	September 2008	$ 347.0

Our acquisitions were financed with a combination of funding from equity contributions, borrowings under our credit facilities and cash flow from operations.

Results of Operations

Year Ended December 31, 2008 Compared to Year Ended December 31, 2009

The following table sets forth selected operating data for the year ended December 31, 2008 compared to the year ended December 31, 2009:

	Years Ended December 31,			
(in thousands, except per unit data)	2008	2009	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 220,219	$ 123,915	$ (96,304)	(43.7)%
Oil sales	9,496	5,706	(3,790)	(39.9)%
Realized commodity derivative gains	26,053	116,550	90,497	347.3%
Unrealized commodity derivative gains (losses)	90,301	(61,186)	(151,487)	*
Gathering and processing	20,421	23,005	2,584	12.7%
Total operating revenues	366,490	207,990	(158,500)	(43.2)%
Operating expenses:				
Lease operating expense	13,350	17,606	4,256	31.9%
Gathering, compression and transportation	29,033	28,190	(843)	(2.9)%
Production taxes	10,281	4,940	(5,341)	(52.0)%
Exploration expense	22,998	10,228	(12,770)	(55.5)%
Impairment of unproved properties	10,112	54,204	44,092	436.0%
Depletion depreciation and amortization	124,821	139,813	14,992	12.0%
Accretion of asset retirement obligations	176	265	89	50.6%
General and administrative	16,171	20,843	4,672	28.9%
Total operating expenses	226,942	276,089	49,147	21.7%
Operating income (loss)	139,548	(68,099)	(207,647)	*

Table of Contents

(in thousands, except per unit data)	Years Ended December 31, 2008	2009	Amount of Increase (Decrease)	Percent Change
Other income expense:				
Interest expense	$ (37,594)	$ (36,053)	$ (1,541)	(4.1)%
Relized and unrealized interest rate derivative gains (losses)	(15,245)	(4,985)	(10,260)	(67.3)%
Total other expense	(52,839)	(41,038)	(11,801)	(22.3)%
Income (loss) before income taxes	86,709	(109,137)	(195,846)	*
Provision for income taxes (expense) benefit	(3,029)	2,605	5,634	*
Net income (loss)	83,680	(106,532)	(190,012)	*
Non-controlling interest in net income of consolidated subsidiary	276	363	87	*
Net income (loss) attributable to Antero stockholders	$ 83,956	$ (106,169)	$ (190,125)	*
Production data:				
Natural gas (Bcf)	30.3	35.1	4.8	15.8%
Oil (MBbl)	114.9	114.0	(0.9)	(0.8)%
NGLs (Bcfe)(1)	0.9	2.6	1.7	188.9%
Combined (Bcfe)	31.9	38.4	6.5	20.4%
Daily combined production (MMcfe/d)	87.4	105.2	17.8	20.4%
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	$ 7.27	$ 3.53	$ (3.74)	(51.4)%
Oil (per Bbl)	$ 82.65	$ 50.05	$ (32.60)	(39.4)%
Combined (per Mcfe)	$ 7.41	$ 3.62	$ (3.79)	(51.1)%
Average realized prices after effects of hedges(2):				
Natural gas (per Mcf)	$ 8.13	$ 6.85	$ (1.28)	(15.7)%
Oil (per Bbl)	$ 82.65	$ 50.05	$ (32.60)	(39.4)%
Combined (per Mcfe)	$ 8.25	$ 6.88	$ (1.37)	(16.6)%
Average Costs (per Mcfe):				
Lease operating costs	$ 0.43	$ 0.49	$ 0.06	14.0%
Gathering, compression and transportation	$ 0.94	$ 0.79	$ (0.15)	(16.0)%
Production taxes	$ 0.33	$ 0.14	$ (0.19)	(57.6)%
Depletion, depreciation amortization and accretion	$ 4.03	$ 3.91	$ (0.12)	(3.0)%
General and administrative	$ 0.52	$ 0.58	$ 0.06	11.5%

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(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 production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts.

* Not meaningful or applicable

Natural gas and oil sales Revenues from production of natural gas and oil decreased from $229.7 million for the year ended December 31, 2008 to $129.6 million for the year ended December 31, 2009, a decrease of $100.1 million or 43.6%. Our production increased by 15.5% from 31.0 Bcfe in 2008 to 35.8 Bcfe in 2009. The net decrease in revenues resulted from commodity price declines which accounted for a $135.7 million decrease (calculated as the decrease in year-to-year

Table of Contents

average price times current year production volumes) in revenues as partially offset by increased production volumes which increased revenues by $35.6 million (calculated as the increase in year-to-year volumes times the prior year average price). Realized gains from our commodity hedging contracts partially offset the effect of these price declines by $116.5 million. The following table sets forth additional information concerning our production volumes for the years ended December 31, 2008 and 2009:

	Years Ended December 31,		
(Bcfe)	**2008**	**2009**	**Percent Change**
Arkoma Woodford	18.7	23.6	26.2%
Piceance Basin	12.3	11.7	(4.8)%
Appalachia		0.5	
Total	31.0	35.8	15.5%

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, 2008 and 2009, our hedges resulted in realized gains of $26.1 million and $116.5 million, respectively. For the years ended December 31, 2008 and 2009, our hedges resulted in unrealized gains of $90.3 million and unrealized losses of $(61.2) million, respectively. Unrealized gains in 2008 occurred as commodity prices began to fall below our fixed price swaps as a result of the weakening U.S. and global economy. During 2009, we realized part of these gains as our 2009 hedge contracts matured and prices began to recover thus partially reversing the unrealized gains recorded in 2008.

Gathering and processing revenues. Gathering and processing revenues increased from $20.4 million for the year ended December 31, 2008 to $23.0 million for 2009 as our plants increased utilization and recoveries.

Lease operating expenses. Lease operating expenses increased from $13.4 million for the year ended December 31, 2008 to $17.6 million in 2009, an increase of 31.9%, primarily as a result of an increase in Arkoma Woodford production volumes and increased water disposal costs in the Piceance Basin. On a per-Mcfe basis, lease operating expenses increased in total from $0.43 per Mcfe in 2008 to $0.49 per Mcfe in 2009 because of the increase in Piceance costs vs. Arkoma costs. In August 2009, two water injection wells were completed in the Piceance Basin and we believe this will decrease future water disposal costs. The following table displays the lease operating expense per Mcfe by basin for the years ended December 31, 2008 and 2009:

	Years Ended December 31,			
	2008		2009	
(in thousands, except per Mcfe data)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**
Arkoma Woodford	$ 5,069	$ 0.27	$ 5,336	$ 0.23
Piceance Basin	8,281	$ 0.68	12,242	$ 1.04
Appalachia			28	$ 0.06
Total lease operating expense	$ 13,350	$ 0.43	$ 17,606	$ 0.49

Table of Contents

Gathering, compression and transportation. Gathering, compression and transportation expense decreased from $29.0 million for the year ended December 31, 2008 to $28.2 million in 2009. On a per-Mcfe basis, these expenses decreased from $0.94 per Mcfe for 2008 to $0.79 per Mcfe for 2009 as gathering plant utilization increased and as production has increased in the Arkoma Basin as a proportion of our total production. Gathering expenses are less in the Arkoma Basin than in the Piceance Basin because of higher water production rates in the Piceance Basin.

Production taxes. Total production taxes decreased from $10.3 million for the year ended December 31, 2008 to $4.9 million for the year ended December 31, 2009, primarily as a result of a decrease in natural gas and oil prices. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 3.8% for the year ended December 31, 2009 compared to 4.5% for the year ended December 31, 2008. Production taxes are primarily based on the wellhead values of production and the applicable rates vary across the areas in which we operate. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the applicable production tax rates then in effect.

Exploration expense. Exploration expense decreased from $23.0 million for the year ended December 31, 2008 to $10.2 million for the year ended December 31, 2009. Exploration expense during 2009 primarily consisted of $1.0 million of seismic costs, $1.7 million in dry hole costs, $5.0 million of standby rig costs and $2.5 million of contract landman costs that did not result in leasehold acquisitions. Exploration expense for 2008 primarily consisted of $5.5 million for seismic programs in the Arkoma and Piceance areas, $6.6 million of dry hole costs, $6.0 million in impairment of rig upgrades and $4.9 million of contract landman costs that did not result in leasehold acquisitions.

Impairment of unproved properties. Our impairment of unproved property expense increased from $10.1 million for the year ended December 31, 2008 to $54.2 million for the year ended December 31, 2009, primarily because at this time we believe we will not renew or drill on certain leaseholds within our Ardmore and Arkoma Basin acreage which are expiring at various dates through December 31, 2010. 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 remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

Depreciation, depletion and amortization (DD&A). DD&A increased from $124.8 million for year ended December 31, 2008 to $139.8 million for the year ended December 31, 2009, an increase of $15.0 million, primarily as a result of increased production for 2009 compared to 2008. DD&A per Mcfe decreased slightly from $4.03 per Mcfe during 2008 to $3.91 per Mcfe during 2009.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2008 or 2009 for proved properties. We had $11.9 million of exploratory well costs at December 31, 2009 included in natural gas and oil properties pending determination of whether proved reserves could be assigned to these well costs. These costs result primarily from development activity in the Marcellus Shale. As of December 31, 2009, no significant well costs have been deferred for over one year pending proved reserves determination.

General and administrative. General and administrative expense increased from $16.2 million for the year ended December 31, 2008 to $20.8 million during 2009, an increase of $4.6 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

Table of Contents

program and production levels. On a per-Mcfe basis, general and administrative expense increased from $0.52 per Mcfe during the year ended December 31, 2008 to $0.58 per Mcfe during 2009.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense decreased from $37.6 million for the year ended December 31, 2008 to $36.1 million during 2009, a decrease of $1.5 million, primarily as a result of lower market interest rates in 2009. In November 2009, we issued $375.0 million of 9.375% senior notes, and in January 2010, we issued an additional $150.0 million of the same series of 9.375% senior notes. The fixed interest rate on these senior notes is significantly higher than the variable rate we have been paying on our bank credit facility borrowings and on our second lien debt facility (which was repaid in full with the net proceeds of the November 2009 senior notes offering). As a result, interest expense in 2010 is expected to be significantly higher than 2009 or 2008 levels.

We have entered into various variable-to-fixed interest rate swap agreements that hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. During 2009, we had interest rate swaps outstanding for a notional amount of $426.0 million with fixed pay rates ranging from 2.79% to 4.11% and terms expiring from December 2009 through July 2011. During the year ended December 31, 2009, we realized a loss on interest rate swap agreements of $11.1 million; whereas, during 2008 we had a realized loss on interest rate swap agreements of $1.4 million. At December 31, 2009, the estimated fair value of our interest rate swap agreements was a liability of $11.1 million, which is included in current and long-term liabilities. As of December 31, 2009, we were in a liability position on our interest rate swaps because of the large decline in interest rates since having entered into the agreements. The amount of future gain or loss actually recognized on such swaps is dependent upon future interest rates, which will affect the value of the swaps. Additionally, we did not terminate the portion of the interest rate swaps related to the $225 million second lien term loan facility when it was repaid in November 2009; therefore, a portion of our interest rate swaps do not currently have floating rate debt associated with them.

Income tax expense. Income tax expense reflects the fact that each of the operating entities files separate federal and state income tax returns; therefore, our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. In general, none of the operating entities have 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. Accordingly, valuation allowances have generally been established against net operating loss (NOLs) carryforwards to the extent that such NOLs exceed net deferred tax liabilities resulting in no income tax expense or benefit. During the year ended December 31, 2008, the operating entities had significant net income on a combined basis primarily related to unrealized derivative gains which are not taxable until realized. Net income tax expense in 2008 reflects the net deferred tax liabilities relating to these unrealized derivative gains which were partially offset by a decrease in the valuation allowance. During the year ended December 31, 2009, we recognized a tax benefit to the extent of existing deferred tax liabilities. We have not recognized the full value of these net operating losses on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit for the full amount of the loss carryforward over time. At December 31, 2009, the operating entities had a combined total of approximately $276 million of NOLs, which expire starting in 2024 and through 2029. Congress recently proposed legislation that would 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 legislation is enacted.

Table of Contents

Year Ended December 31, 2007 Compared to Year Ended December 31, 2008

The following table sets forth selected operating data for the year ended December 31, 2007 compared to the year ended December 31, 2008:

(in thousands, except per unit data)	Year Ended December 31, 2007	Year Ended December 31, 2008	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 63,975	$ 220,219	$ 156,244	244.2%
Oil sales	3,749	9,496	5,747	153.3%
Realized commodity derivative gains	14,373	26,053	11,680	81.3%
Unrealized commodity derivative gains	4,619	90,301	85,682	1,855.0%
Gathering and processing	4,778	20,421	15,643	327.4%
Total operating revenues	91,494	366,490	274,996	300.6%
Operating expenses:				
Lease operating expense	4,435	13,350	8,915	201.0%
Gathering, compression and transportation	10,016	29,033	19,017	189.9%
Production taxes	2,233	10,281	8,048	360.4%
Exploration expense	17,970	22,998	5,028	28.0%
Impairment of unproved properties	4,995	10,112	5,117	102.4%
Depletion, depreciation and amortization	50,091	124,821	74,730	149.2%
Accretion of asset retirement obligations	68	176	108	158.8%
General and administrative	11,682	16,171	4,489	38.4%
Total operating expenses	101,490	226,942	125,452	123.6%
Operating income (loss)	(9,996)	139,548	149,544	*
Other income (expense):				
Interest expense	$ (25,124)	$ (37,594)	$ (12,470)	49.6%
Realized and unrealized interest rate derivative losses	(3,033)	(15,245)	(12,212)	402.6%
Total other expense	(28,157)	(52,839)	(24,682)	87.7%
Income (loss) before income taxes	(38,153)	86,709	124,862	*
Provision for income tax (expense) benefit	400	(3,029)	(3,429)	*
Net income (loss)	(37,753)	83,680	121,433	*
Non-controlling interest in net income of consolidated subsidiary		276	276	*
Net income (loss) attributable to Antero stockholders	$ (37,753)	83,956	121,709	*
Production data:				
Natural gas (Bcf)	10.9	30.3	19.4	178.0%
Oil (MBbl)	49.4	114.9	65.5	132.6%
NGLs (Bcfe)(1)		0.9	0.9	*
Combined (Bcfe)	11.2	31.9	20.7	184.8%
Daily combined production (MMcfe/d)	30.8	87.4	56.6	183.8%

Average prices before effects of hedges(2):							
Natural gas (per Mcf)	$	5.85	$	7.27	$	1.42	24.3%
Oil (per Bbl)	$	76.51	$	82.57	$	6.06	7.9%
Combined (per Mcfe)	$	6.03	$	7.41	$	1.38	22.9%

Table of Contents

(in thousands, except per unit data)	Year Ended December 31, 2007	2008	Amount of Increase (Decrease)	Percent Change
Average realized prices after effects of hedges(2):				
Natural gas (per Mcf)	$ 6.49	$ 8.13	$ 1.64	25.3%
Oil (per Bbl)	$ 76.51	$ 82.57	$ 6.06	7.9%
Combined (per Mcfe):	$ 6.65	$ 8.25	$ 1.60	24.1%
Average costs (per Mcfe):				
Lease operating costs	$ 0.39	$ 0.43	$ 0.04	10.3%
Gathering, compression and transportation	$ 0.89	$ 0.94	$ 0.05	5.6%
Production taxes	$ 0.20	$ 0.33	$ 0.13	65.0%
Depletion, depreciation, amortization	$ 4.46	$ 4.03	$ (0.43)	(9.6)%
General and administrative	$ 1.04	$ 0.52	$ (0.52)	(50.0)%

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(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 production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts.

* Not meaningful or applicable.

Natural gas and oil sales. Revenues from sales of natural gas and oil increased to $229.7 million for the year ended December 31, 2008 from $67.7 million for the year ended December 31, 2007, an increase of 239%. Our annual production increased by 176.8% from 11.2 Bcfe in 2007 to 31.0 Bcfe in 2008 due to increased production in the Arkoma Woodford and Piceance Basins. This net increase in production added approximately $119.1 million of production revenues, and the increase in prices on a per-Mcfe basis increased production revenues by approximately $42.9 million. The following table presents additional information concerning our production for the years ended December 31, 2007 and 2008:

(in Bcfe)	Year Ended December 31, 2007	2008	Percent Increase
Arkoma Woodford	6.3	18.7	196.8%
Piceance Basin	4.9	12.3	151.0%
Total	11.2	31.0	176.8%

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 currently 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 from future production. In 2008, approximately 59% of our natural gas volumes were hedged, which resulted in a realized gain on such hedges of $26.1 million. In 2007, we hedged approximately 81% of our natural gas volumes, which resulted in realized gains on such hedges of $14.4 million. Unrealized gains in these periods were

Table of Contents

$4.6 million and $90.3 million in 2007 and 2008, respectively. The significant unrealized gains in 2008 are attributable to the sharp decline in natural gas prices in the fourth quarter as a result of market turmoil and a weakened U.S. and global economy.

Gathering and processing revenues. Gathering and processing revenues increased from $4.8 million in 2007 to $20.4 million in 2008 primarily as a result of recognizing a full year of operations for our Coalgate plant in Oklahoma, which began processing volumes in September 2007. Additionally, in February 2008, we entered into a joint venture with MarkWest and began operating our two processing plants under our Centrahoma joint venture.

Lease operating expense. Lease operating expenses increased from $4.4 million in 2007 to $13.4 million in 2008, an increase of 201% primarily as a result of an increase in our production volumes. On a per-Mcfe basis, lease operating expenses increased from $0.39 per Mcfe in 2007 to $0.43 per Mcfe in 2008 primarily due to increased water disposal expenses in the Piceance Basin. The following table displays our lease operating expenses per Mcfe by basin:

	Year Ended December 31,			
	2007		2008	
(in thousands, except per Mcfe data)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**
Arkoma Woodford	$ 1,758	$ 0.28	$ 5,069	$ 0.27
Piceance Basin	$ 2,677	$ 0.54	$ 8,281	$ 0.68
Total lease operating expense	$ 4,435	$ 0.39	$ 13,350	$ 0.43

Gathering, compression and transportation. Gathering and transportation expense increased from $10.0 million in 2007 to $29.0 million in 2008 primarily as a result of an increase in production. On a per-Mcfe basis, these expenses increased from $0.89 per Mcfe in 2007 to $0.94 per Mcfe as a result of start-up expenses for the Coalgate plant.

Production taxes. Total production taxes increased from $2.2 million in 2007 to $10.3 million in 2008 primarily as a result of an increase in natural gas and oil revenues before the effects of hedging. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 4.5% for 2008 and 3.3% for 2007. Production taxes are primarily based on the wellhead values of production, and the tax rates vary across the different areas in which we operate. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the production tax rates in effect.

Exploration expense. Exploration expense increased from $18.0 million in 2007 to $23.0 million in 2008. Exploration expense for 2008 consisted of $5.5 million for seismic programs in the Arkoma and Piceance areas, $6.6 million in dry hole costs, $6.0 million in impairment of rig upgrades and $4.9 million of contract landman costs that did not result in leasehold acquisitions. Exploration expense for 2007 consisted of $9.8 million for seismic programs in the Arkoma Woodford and Piceance areas, $4.4 million of dry hole costs and $3.8 million of contract landman costs that did not result in leasehold acquisitions.

Impairment of unproved properties. Our impairment of unproved property expense increased from $5.0 million in 2007 to $10.1 million in 2008, primarily because we elected to abandon certain leaseholds within our Ardmore Basin acreage and certain non-core Arkoma Basin acreage. 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 remaining lease terms, reservoir performance, commodity price outlook or future plans to develop the acreage and accordingly recognize corresponding impairment costs.

Table of Contents

Depreciation, depletion and amortization (DD&A). DD&A increased from $50.1 million in 2007 to $124.8 million in 2008, an increase of $74.7 million, primarily as a result of increased production in 2008 as compared to 2007. The weighted average DD&A rate decreased from $4.46 per Mcfe during 2007 to $4.03 per Mcfe during 2008 because our exploration, development and acquisition costs (total funding costs) have declined on a per Mcf basis in our two primary producing areas.

Under successful efforts accounting, DD&A expense is separately computed for each producing area based on geologic and reservoir delineation. The capital expenditures for each producing area compared to the proved reserves corresponding to each producing area determine a weighted average DD&A rate for current production. Future DD&A rates will be adjusted to reflect future capital expenditures and proved reserve changes in specific areas. We anticipate that DD&A expense per unit will decline over time as our development projects mature.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the property's estimated fair value, we adjust the carrying amount of the property to fair value through a charge-to-impairment expense. There were no impairment expenses recorded in 2007 or 2008 for proved properties. Additionally, there were no exploratory wells in progress at December 31, 2007 or 2008 included in unevaluated natural gas and oil properties pending determination of whether proved reserves could be assigned to any such wells.

General and administrative. General and administrative expense increased from $11.7 million in 2007 to $16.2 million in 2008, an increase of $4.5 million, primarily as a result of increased costs of $2.7 million related to salaries and employee benefits for additional personnel required for our capital program and production activities. As of December 31, 2008, we had 56 full-time employees, compared to 40 full-time employees as of December 31, 2007. On a per-Mcfe basis, general and administrative expense decreased from $1.04 per Mcfe in 2007 to $0.52 per Mcfe in 2008 primarily as a result of an increase in production volumes without a corresponding increase in general and administrative expense.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased from $25.1 million in 2007 to $37.6 million in 2008, primarily as a result of higher average outstanding debt balances in 2008 in order to fund our exploration and development activities. While interest rates on our senior secured revolving credit facility and second lien term loan facility decreased during 2008 from 2007 levels, average borrowings outstanding increased from approximately $259.5 million during 2007 to approximately $538.1 million during 2008.

We have entered into various variable-to-fixed interest rate swap agreements that hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. At December 31, 2008, we had interest rate swaps outstanding for a notional amount of $426.0 million with fixed pay rates ranging from 2.79% to 4.11% and terms expiring from December 2009 through July 2011. During 2008, we realized losses on interest rate swap agreements of $1.4 million, whereas, during 2007, we realized a gain on interest rate swap agreements of $0.4 million. At December 31, 2008, the estimated fair value of our interest rate swap agreements was a liability of $17.3 million, which is included in current and long-term liabilities. As of such date, we were in a liability position on our interest rate swaps because of the large decline in interest rates since having entered into the agreements. The amount of future gain or loss actually recognized on such swaps is dependent upon future interest rates, which will affect the value of the swaps.

Income tax expense. Income tax expense reflects the fact that each of the operating entities files separate federal and state income tax returns; therefore our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. In general, none of the operating entities have 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

Table of Contents

drilling costs. Accordingly, valuation allowances have generally been established against net operating loss (NOLs) carryforwards to the extent that such NOLs exceed net deferred tax liabilities resulting in no income tax expense or benefit in prior years. During the year ended December 31, 2008, the operating entities had significant net income on a combined basis primarily related to unrealized derivative gains which are not taxable until realized and, accordingly, we recognized related deferred tax expense. This deferred income tax expense was substantially offset by a reduction in valuation allowances. At December 31, 2008, the operating entities had a combined total of approximately $156.9 million of NOLs, which expire starting in 2024 and through 2029. We have not recognized the full value of these net operating losses on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit for the full amount of the loss carryforward over time. Congress recently proposed legislation that would eliminate or limit future deductions for intangible drilling costs and could adversely affect our future taxable position. The impact of any change is recorded in the period that legislation is enacted.

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2010

The following table sets forth selected operating data for the three months ended March 31, 2009 compared to the three months ended March 31, 2010:

	Three Months Ended March 31,		Amount of Increase (Decrease)	Percent Change
(in thousands, except per unit data)	**2009**	**2010**		
Operating revenues:				
Natural gas sales	$ 37,332	53,952	16,620	44.5%
Oil sales	1,063	2,114	1,051	98.9%
Realized commodity derivative gains	33,572	12,271	(21,301)	(63.4)%
Unrealized commodity derivative gains (losses)	5,114	98,812	93,698	1,832.2%
Gathering and processing	4,379	6,413	2,034	46.4%
Total operating revenues	81,460	173,562	92,102	113.1%
Operating expenses:				
Lease operating expense	6,945	4,598	(2,347)	(33.8)%
Gathering compression and transportation	6,375	10,141	3,766	59.1%
Production taxes	1,832	2,670	838	45.7%
Exploration expense	2,429	1,352	(1,077)	(44.3)%
Impairment of unproved properties	7,767	2,262	(5,505)	(70.9)%
Depletion, depreciation and amortization	39,701	32,996	(6,705)	(16.9)%
Accretion of asset retirement obligations	62	73	11	17.7%
General and administrative	4,406	4,412	6	0.1%
Total operating expenses	69,517	58,504	(11,013)	(15.8)%
Operating income (loss)	11,943	115,058	103,115	863.4%

Table of Contents

(in thousands, except per unit data)	Three Months Ended March 31, 2009	Three Months Ended March 31, 2010	Amount of Increase (Decrease)	Percent Change
Other income expense:				
Interest expense	(7,178)	(13,292)	(6,114)	85.2%
Realized interest rate derivative gains (losses)	(2,072)	(3,127)	(1,055)	50.9%
Unrealized interest rate derivative gains (losses)	697	1,525	828	118.8%
Total other income expense	(8,553)	(14,894)	(6,341)	74.1%
Income (loss) before income taxes	3,390	100,164	96,774	*
Provision for income taxes (expense) benefit	1,605	(11,318)	(12,923)	*
Net income (loss)	4,995	88,446	83,451	*
Non-controlling interest in net (loss) income of consolidated subsidiary	159	(1,241)	(1,400)	*
Net income (loss) attributable to Antero stockholders	$ 5,154	$ 87,605	$ 82,451	*
Production data:				
Natural gas (Bcf)	9.7	9.9	0.2	2.1%
Oil (MBbl)	30.8	31.9	1.1	3.6%
NGLs (Bcfe)(1)	0.7	0.5	(0.2)	(28.6)%
Combined (Bcfe)	10.6	10.6	0.0	0.0%
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	$ 3.84	$ 5.47	$ 1.63	42.4%
Oil (per Bbl)	$ 34.51	$ 66.27	$ 31.76	92.0%
Combined (per Mcfe)	$ 3.87	$ 5.57	$ 1.70	43.9%
Average realized prices after effects of hedges(2):				
Natural gas (per Mcf)	$ 7.28	$ 6.71	$ (0.57)	(7.8)%
Oil (per Bbl)	$ 34.51	$ 66.27	$ 31.76	92.0%
Combined (per Mcfe)	$ 7.26	$ 6.79	$ (0.47)	(6.5)%
Average Costs (per Mcfe):				
Lease operating costs	$ 0.70	$ 0.46	$ (0.24)	(34.3)%
Gathering, compression and transportation	$ 0.64	$ 1.01	$ 0.37	57.8%
Production taxes	$ 0.18	$ 0.27	$ 0.09	50.0%
Depletion, depreciation, amortization and accretion	$ 4.00	$ 3.28	$ (0.72)	(18.0)%
General and administrative	$ 0.44	$ 0.44	$ 0.00	0.0%

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(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 production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts.

* Not meaningful or applicable

Natural gas and oil sales. Revenues from production of natural gas and oil increased from $38.4 million for the three months ended March 31, 2009 to $56.1 million for the three months ended March 31, 2010, an increase of 46%. Our production increased slightly, from 9.9 Bcfe for the three months ended March 31, 2009 to 10.1 Bcfe for the three months ended March 31, 2010; however, prices increased by 44% before the effect of realized hedge gains. After the effect of realized hedge gains, our realized price per Mcfe decreased from $7.26 per Mcfe for the three months ended March 31, 2009 to $6.79 per Mcfe for the 2010 period. The net increase in realized oil and gas revenues resulted from production increases, which accounted for a $0.6 million increase in revenues, and price increases which increased revenues by $17.1 million. The following table sets forth additional information concerning our production volumes for the three months ended March 31, 2009 and 2010:

(Bcfe)	Three Months Ended March 31, 2009	2010	Percent Change
Arkoma Woodford	6.6	5.9	(11)%
Piceance Basin	3.3	2.7	(18)%
Appalachia		1.5	
Total	9.9	10.1	2.0%

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 three months ended March 31, 2009 and 2010, our hedges resulted in realized gains of $33.6 million and $12.3 million, respectively. For the three months ended March 31, 2009 and 2010, our hedges resulted in unrealized gains of $5.1 million and $98.8 million, respectively. Unrealized gains occurred as commodity prices at March 31, 2009 and 2010 were below our fixed price swaps. Should natural gas prices increase from their March 31, 2010 levels, these unrealized gains at March 31, 2010 will reverse.

Gathering and processing revenues. Gathering and processing revenues increased from $4.4 million for the three months ended March 31, 2009 to $6.4 million for the three months ended March 31, 2010 because of increased utilization and recoveries and increases in prices received for NGLs from the prior year period.

Lease operating expenses. Lease operating expenses decreased from $6.9 million for the three months ended March 31, 2009 to $4.7 million for the three months ended March 31, 2010, a decrease of 31.9%, primarily as a result of the decrease in water disposal costs in the Piceance Basin. On a per-Mcfe basis, lease operating expenses decreased from $0.70 per Mcfe for the three months ended March 31, 2009 to $0.47 per Mcfe for the respective 2010 period. In August 2009, two water injection wells were completed in the Piceance Basin which decreased water disposal costs compared to the prior year period. The following table displays the lease operating expense per Mcfe by basin for the three months ended March 31, 2009 and 2010:

	Three months ended March 31, 2009		2010	
(in thousands, except per Mcfe data)	Amount	Per Mcfe	Amount	Per Mcfe
Arkoma Woodford	$ 1,692	$ 0.25	$ 1,356	$ 0.23
Piceance Basin	5,253	$ 1.60	2,915	$ 1.07
Appalachia			327	$ 0.22
Total lease operating expense	$ 6,945	$ 0.70	$ 4,598	$ 0.46

Gathering, compression and transportation. Gathering, compression and transportation expense increased from $6.4 million for the three months ended March 31, 2009 to $10.1 million for the three months ended March 31, 2010. On a per-Mcfe basis, these expenses increased from $0.64 per Mcfe for the three months ended March 31, 2009 to $1.01 per Mcfe for the 2010 period primarily because of increased contractual transportation costs for Arkoma Woodford and Piceance basin production related to new transportation contracts. Increased transportation costs were partially offset by increased pricing received at new delivery points.

Production taxes. Total production taxes increased from $1.8 million for the three months ended March 31, 2009 to $2.6 million for the three months ended March 31, 2010, primarily as a result of the increase in natural gas and oil prices. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 4.8% for the three months ended March 31, 2009 and 4.7% for the three months ended March 31, 2010. Production taxes are primarily based on the wellhead values of production and the applicable rates vary across the areas in which we operate. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the applicable production tax rates then in effect.

Exploration expense. Exploration expense decreased from $2.4 million for the three months ended March 31, 2009 to $1.4 million for the three months ended March 31, 2010, primarily because of $0.9 million in impairment charges related to rig update costs during the three months ended March 31, 2009.

Impairment of unproved properties. Our impairment of unproved property expense decreased from $7.8 million for the three months ended March 31, 2009 to $2.3 million for the three months ended March 31, 2010. We had higher costs in the prior year because we elected to abandon certain leaseholds within our non-core Ardmore Basin acreage and certain non-core Arkoma Basin acreage. 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 remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

Depreciation, depletion and amortization (DD&A). DD&A decreased from $39.7 million for three months ended March 31, 2009 to $33.0 million for the three months ended March 31, 2010, a decrease of $6.7 million, primarily as a result of increased proved developed reserve quantities in 2010 compared to 2009 because of changes in pricing due to new SEC rules, which affected our depletion rates beginning with the fourth quarter of 2009. Production rates also decreased in the Arkoma and Piceance basins. DD&A per Mcfe decreased from $4.00 per Mcfe during the three months ended March 31, 2009 to $3.27 per Mcfe during the three months ended March 31, 2010.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the three months ended March 31, 2009 or 2010 for proved properties. As of March 31, 2010, no significant well costs have been deferred for over one year pending proved reserves determination.

General and administrative. General and administrative expenses remained constant at $4.4 million for the three months ended March 31, 2009 and 2010. Increased salaries and benefits for the three months ended March 31, 2010 compared to the three months end March 31, 2009 due to the addition of full-time personnel of approximately $0.5 million were offset by decreases in stock compensation expense, franchise tax expense, and miscellaneous other expenses. On a per-Mcfe basis, general and administrative expense remained constant at $0.44 per Mcfe for the three months ended March 31, 2009 and 2010.

Table of Contents

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased from $7.2 million for the three months ended March 31, 2009 to $13.3 million for the three months ended March 31, 2010 because of the issuance of $375.0 million of 9.375% senior notes in November 2010 and $150 million of the same series of notes in January 2010. The fixed interest rate on these senior notes is significantly higher than the variable rates we paid during the first three months of 2009 on borrowings under our senior secured revolving credit facility and the second lien term loan facility (which were the primary sources of borrowings during the three months ended March 31, 2009).

As of March 31, 2010, we had an interest rate swap outstanding for a notional amount of $225 million with a fixed pay rate of 4.11% with a term expiring July 2011. During the three months ended March 31, 2009, we realized a loss on interest rate swap agreements of $2.1 million; whereas, during the three months ended March 31, 2010 we had a realized loss on interest rate swap agreements of $3.1 million. At March 31, 2010, the estimated fair value of our interest rate swap was a liability of $9.6 million, which is included in current and long-term liabilities. As of March 31, 2010, we were in a liability position on our interest rate swap because of the large decline in interest rates since having entered into the agreement. The amount of future gain or loss actually recognized on such swap is dependent upon future interest rates, which will affect the value of the swaps. We did not terminate the interest rate swap related to the $225 million second lien term loan facility when it was repaid in November 2009; therefore, this swap does not currently have floating rate debt associated with it. As of March 31, 2010, there were no borrowings outstanding under the senior secured revolving credit facility.

Income tax expense. Income tax expense reflects the fact that each of the operating entities files separate federal and state income tax returns; therefore, our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. None of the operating entities have generated current taxable income in either the current or prior periods, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. Accordingly, valuation allowances have generally been established against net operating loss (NOLs) carryforwards to the extent that such NOLs and other deferred tax assets exceed deferred tax liabilities resulting in no income tax expense or benefit for those subsidiaries having deferred tax assets in excess of deferred tax liabilities. We have not recognized the full value of these NOLs on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit for the full amount of the loss carryforwards over time.

Certain subsidiaries had net deferred tax liabilities at March 31, 2010, resulting from unrealized gains on commodity derivatives and basis differences in assets, resulting in the provision of $11.3 million of deferred tax expense during the first quarter of 2010.

The tax benefit of $1.6 million for the three months ended March 31, 2009 resulted from the reversal of previously recorded deferred tax liabilities as a result of operating losses incurred in the first quarter of 2009 by one of the operating entities.

At December 31, 2009, the operating entities had a combined total of approximately $276 million of NOLs, which expire starting in 2024 and through 2029. Congress recently proposed legislation that would eliminate or limit future deductions for intangible drilling costs and could significantly affect our future taxable position. The impact of any change is recorded in the period that legislation is enacted.

Capital Resources and Liquidity

Our primary sources of liquidity have been through issuances of equity securities, borrowings under bank credit facilities, our second lien term loan facility, our senior notes, and net cash provided by operating activities. Our primary use of cash has been for the exploration, development and acquisition of natural gas and oil properties. As we pursue reserve and production growth, we continually monitor

Table of Contents

what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us. We have approximately 16,000 potential drilling locations, of which only approximately 9.8% are included in our proved reserve base as of December 31, 2009. We would be required to generate or raise significant capital to conduct drilling activities on these potential drilling locations.

In November 2009, we adjusted our capital structure by issuing $375 million of 9.375% senior notes due 2017 at a discount of $2.6 million and approximately $124 million of additional equity. The net proceeds of the November 2009 senior notes offering and equity offerings were used to repay in full our $225 million second lien term loan facility, which was due to mature in 2014, and to repay a portion of the borrowings outstanding under our senior secured revolving credit facility. In January 2010, we issued an additional $150 million of the same series of 9.375% senior notes at a premium of $6 million and used the net proceeds to repay the remaining outstanding borrowings under the senior secured revolving credit facility. At March 31, 2010, we had a borrowing base under the bank credit facility of $369 million and $11.4 million of outstanding letters of credit, giving us net available borrowings on the facility of approximately $357.6 million. On May 12, 2010, the borrowing base was redetermined at $400 million (the maximum available under the facility), providing us with available borrowing capacity as of such date of approximately $361 million.

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 cash flows from operations despite potential further 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. Over the last two years, dislocations in the credit markets, steep stock market declines, financial institution failures and government capital infusions reflected a weakened global economy and financing transactions have been difficult to complete as a result. Our current senior secured revolving credit facility is backed by a syndicate of 13 banks. We believe that our current syndicate banks 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.

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

For more information on our outstanding indebtedness, see " Cash Flow Provided by Financing Activities."

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $24.7 million, $157.5 million and $149.3 million for the years ended December 31, 2007, 2008 and 2009, respectively, and $66.6 million and $52.0 million for the three months ended March 31, 2009 and 2010, respectively. The decrease in cash flow from operations from 2008 to 2009 was primarily the result of lower gas prices in 2009. The increase in cash flow from operations for the year ended December 31, 2008 compared to 2007 was primarily the result of an increase in natural gas and oil production and prices. The decrease in cash flows for the three months ended March 31, 2009 compared to the three months ended March 31, 2010 was the result of the decrease in realized prices for production after the effect of hedges and changes in working capital levels.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas and oil production. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather, infrastructure

Table of Contents

capacity to reach markets and other variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see Quantitative and Qualitative Disclosure About Market Risk" below.

Cash Flow Used in Investing Activities

During the years ended December 31, 2007, 2008 and 2009 and the three months March 31, 2009 and 2010, we had cash flows used in investing activities of $600.9 million, $1.0 billion, $281.9 million, $115.3 million and $66.0 million, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. The decrease in cash used in investing activities in 2009 from 2008 of $722 million is a result of the $361.4 million investment in the Appalachian Basin in 2008 and curtailed investment and drilling activity in 2009 in all our projects in response to the decline in oil and gas prices in 2009. The increase in cash flows used in investing activities during the year ended December 31, 2008 compared to the prior year period is a result of an increase in the capital program in the Piceance Basin as well as leasehold acquisition costs incurred in the Appalachian Basin totaling $361.4 million. The decrease in cash used in investing activities for the three months ended March 31, 2009 compared to the three months ended March 31, 2010 was a result of lower levels of drilling activity. We expect that our cash used in investing activities for the remainder of 2010 will be at a higher quarterly rate based on our current capital budget and planned drilling activities.

Our capital expenditures for drilling, development and acquisition costs for the years ended December 31, 2007, 2008 and 2009 are summarized in the following table. Capital expenditures reflected in the table below differ from the amounts shown in the statements of cash flows in the financial statements because amounts reflected in the table include changes in accounts payable from the previous reporting period for capital expenditures, while the amounts in the statements of cash flows in the financial statements are presented on a cash basis.

	Year Ended December 31,		
(in thousands)	**2007**	**2008**	**2009**
Arkoma Basin	$ 409,465	$ 335,516	$ 77,841
Piceance Basin	147,094	297,285	51,250
Appalachian Basin		361,379	68,355
Gas plant, gathering, pipeline, and other	89,910	47,568	6,008
Total capital expenditures	$ 646,469	$ 1,041,748	$ 203,454

Our board of directors has approved a capital budget of up to $366 million for 2010. 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 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 2009 of $104.3 million was primarily the result of cash provided by, (i) the issuance of the senior notes (net of discounts and issuance costs) of $361 million,

Table of Contents

(ii) the issuance of preferred stock of $105.0 million, and (iii) the issuance of member units in Antero Resources LLC for $123.6 million (net of $1.4 million of issuance costs); net of cash applied to (i) net repayments on the bank credit facility of $254.5 million and (ii) the repayment of the second lien term loan facility of $225.0 million.

Net cash provided by financing activities of $874.4 million during the year ended December 31, 2008 was primarily the result of the issuance of $670.0 million of Series B preferred stock and $207.2 million of net borrowings under our senior secured revolving credit facility. Net cash provided by financing activities of $585.3 million during the year ended December 31, 2007 was primarily the result of the issuance of $253.8 million of preferred stock, borrowings of $225.0 million under the second lien term loan facility, and $106.9 million of net borrowings on our senior secured revolving credit facility.

Net cash provided by financing activities for the three months ended March 31, 2009 of $9.7 million was the result of the issuance of $105 million of preferred stock, the proceeds of which were used to reduce borrowings outstanding under our senior secured revolving credit facility by $90 million and to pay cash financing costs of $6.4 million. Net cash provided by financing activities of $9.6 million for the three months ended March 31, 2010 was the result of the issuance of $150 million of 9.375% senior notes at a premium of $6 million, the proceeds of which were used to reduce borrowings outstanding under our senior secured revolving credit facility by $142.1 million and to pay cash financing costs of $4.2 million.

Senior Secured Revolving Credit Facility. Our senior secured revolving credit facility was amended and restated as of January 14, 2009 and amended in October and November 2009 and in January and May 2010 and matures on March 15, 2012. As of March 31, 2010, we had letters of credit outstanding under our senior secured revolving credit facility of approximately $11 million and a borrowing base thereunder of $369 million. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility. Future borrowing bases will be computed based on proved natural gas and oil reserves and estimated future cash flow from these reserves and hedge positions, as well as any other outstanding indebtedness. The borrowing base is redetermined semiannually; the next redetermination is scheduled to occur in October 2010. Following the next scheduled borrowing base redetermination, we may be subject to similar restrictions on our ability to incur indebtedness or our borrowing base may be reduced.

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 200 to 300 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 an applicable margin ranging from 100 to 200 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 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 Disclosure About Market Risk Interest Rate Risks and Hedges."

As of December 31, 2008 and 2009, borrowings outstanding under our senior secured revolving credit facility totaled $396.6 million and $142.1 million, respectively, and had a weighted average interest rate (excluding the impact of our interest rate swaps) of 5.0% and 2.36%, respectively. At

March 31, 2010, we had no borrowings and $11.4 million of letters of credit outstanding under the senior secured revolving credit facility. 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;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The senior revolving credit facility also requires us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets to our consolidated current liabilities, of not less than 1.0 to 1.0 as of the end of each fiscal quarter; and
- a leverage ratio, which is the ratio of our consolidated funded indebtedness (minus amounts of unsatisfied capital calls) as of the end of such fiscal quarter to our consolidated EBITDAX for the trailing four fiscal quarter period, of not greater than 4.0 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2009 and 2008 and as of March 31, 2010.

Second Lien Term Loan Facility. We repaid our $225.0 million second lien term loan facility in full with the net proceeds of the November 2009 offering of notes. The principal amount borrowed under the second lien term loan facility was payable on the maturity date, with such amount borrowed bearing interest, payable quarterly. Interest accrued on Eurodollar loans at a rate per annum equal to the Eurodollar rate, plus an applicable margin of 450 basis points. Interest accrued on base rate loans at a rate per annum equal to the greater of (i) the prime lending rate as set forth on the British Banking Association Telerate Page 5 and (ii) the federal funds effective rate plus 50 basis points, plus an applicable margin of 350 basis points. The amounts outstanding under the second lien term loan facility were secured by a second priority lien on substantially all of our natural gas and oil properties and associated assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. The second lien term loan facility contained various covenants including restrictions on our ability to incur indebtedness, dispose of assets, make loans or investments or certain payments, or enter into mergers. The second lien term loan facility also required us to maintain certain financial ratios, including interest coverage, leverage and net present value to funded indebtedness. We were in compliance with such covenants and ratios at December 31, 2008.

Interest Rate Hedges. We have entered into various variable to fixed interest rate swap agreements which hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. At March 31, 2010, we had an interest rate swap outstanding for a notional amount of $225.0 million with a fixed pay rate of 4.11% with a term expiring in July 2011. During the years ended December 31, 2007, 2008 and 2009 and the three months ended March 31, 2009 and 2010, we had realized gains (losses) on interest rate swap agreements of $0.4 million, $(1.4) million, $(11.1) million, $2.1 million and $3.1 million, respectively. At March 31, 2010, we had unrealized losses on our interest rate swap agreement of $9.6 million. The amount of future gain or loss actually recognized on such swap is dependent upon future interest rates. See " Quantitative and Qualitative Disclosure About Market Risk Interest Rate Risk and Hedges." We did not terminate the interest rate swap related to the $225.0 million second lien term facility when it was retired in November 2009; therefore, this swap does not currently have debt associated with it.

Capital Leases. We lease certain compressors under agreements that are classified as capital leases having a balance of approximately $1.3 million, $1.2 million and $1.1 million at December 31, 2008 and 2009 and March 31, 2010, respectively.

Commodity Hedging Activities

Our primary market risk exposure is in the price we received for our natural gas 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 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 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 Centerpoint East, CIG Hub, Transco Zone 4 and Columbia Gas Transmission (CGTAP) Indexes.

Our financial hedging activities are intended to support natural gas 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. These contracts may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty and cashless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference.

At December 31, 2009 and March 31, 2010, we had in place natural gas swaps covering portions of production from 2010 through 2014. Our senior secured revolving credit facility allows us to hedge up to 85% of our estimated production from proved reserves for up to 12 months in the future, 75% for 13 to 24 months in the future, 65% for 25 to 36 months in the future, 55% for 37 to 48 months in the future and 45% for 49 to 60 months in the future. Based on our annual production and our fixed price swap contracts in place during 2009, our annual income before taxes for the year ended December 31, 2009 would have decreased by approximately $1.0 million for each $0.10 decrease per MMBtu in natural gas prices and approximately $0.1 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 as mentioned above, 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 2009, approximately 72% of our natural gas volumes were hedged, which resulted in realized gains on hedges of $116.5 million. In 2008, approximately 59% of our natural gas volumes were hedged, which resulted in realized gains on hedges of $26.1 million. In 2007, we hedged approximately 81% of our natural gas volumes, which resulted in realized gains on hedges of $14.4 million.

Table of Contents

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, 2009, the estimated fair value of our commodity derivative instruments was a net asset of $41.1 million comprised of current and noncurrent assets. At March 31, 2010, the estimated fair value of our commodity derivative instruments was a net asset of $139.9 million comprised of current and noncurrent assets.

The table below summarizes the realized and unrealized gains related to natural gas derivative instruments for years ended December 31, 2007, 2008 and 2009 and the three months ended March 31, 2009 and 2010:

	Year Ended December 31,			Three Months Ended March 31,	
(in thousands)	**2007**	**2008**	**2009**	**2009**	**2010**
Realized gains (losses) on commodity derivative contracts	$ 14,373	$ 26,053	$ 116,550	$ 33,572	$ 12,271
Unrealized gains on commodity derivative contracts	4,619	90,301	(61,186)	5,114	98,812
Total	$ 18,992	$ 116,354	$ 55,364	$ 38,686	$ 111,083

As of March 31, 2010, and including swaps entered into since March 31, 2010 through May 14, 2010, we have entered into fixed price natural gas swaps in order to hedge a portion of our natural gas production from 2010 through 2014 as summarized in the following table. Hedge agreements referenced to the Centerpoint, NYMEX and Transco Zone 4 indices are for our production in the Arkoma Basin. Hedge agreements referenced to the CIG index are for our production in the Piceance Basin. Hedge agreements referenced to the CGTAP index are for our production from the Appalachian Basin.

	MMbtu/d	**Weighted average index price**
Year ending December 31, 2010:		
Centerpoint	30,000	$ 7.20
CIG	30,000	$ 5.12
NYMEX	10,000	$ 6.21
CGTAP	20,000	$ 5.98
Year ending December 31, 2011:		
CIG	35,000	$ 5.78
Transco Zone 4	35,000	$ 6.91
CGTAP	30,000	$ 6.60
Year ending December 31, 2012:		
CIG	35,000	$ 6.06
Transco Zone 4	35,000	$ 7.05
CGTAP	30,000	$ 6.66
Year ending December 31, 2013:		
CIG	40,000	$ 5.93
Transco Zone 4	40,000	$ 6.51
CGTAP	30,000	$ 6.64
Year ending December 31, 2014:		
CIG	40,000	$ 6.07
Transco Zone 4	20,000	$ 6.51
CGTAP	50,000	$ 6.54

Centerpoint	10,000	$	6.20

Table of Contents

By removing price volatility from a portion of our expected natural gas production through December 2014, 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.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with four different counterparties, of which all but one are lenders in our senior secured revolving credit facility. As of March 31, 2010, derivative positions with JP Morgan, BNP Paribas, Wells Fargo, KeyBank, Union Bank, and Barclays accounted for approximately 54%, 22%, 10%, 8%, 4%, and 2%, respectively, of the net fair value of our commodity derivative assets position. We believe 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, 2009, we have no past due receivables from or payables to any of our counterparties.

Contractual Obligations. A summary of our contractual obligations as of December 31, 2009 is provided in the following table. Our contractual obligations as of March 31, 2010 have not changed significantly from those summarized in the following table.

	As of December 31,						
(in millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**
Senior secured revolving credit facility(1)	$	$	$ 142.1	$	$	$	$ 142.1
Senior notes interest(2)	35.2	35.2	35.2	35.2	35.2	102.6	278.6
Senior notes principal(2)						375.0	375.0
Capital leases	0.2	0.2	0.2	0.2	0.2	0.4	1.4
Drilling rig commitments(3)	9.7						9.7
Derivative instruments(4)	8.6	2.5					11.1
Asset retirement obligations(5)						3.5	3.5
Office and equipment leases	0.6	0.6	0.3	0.1			1.6
Total	$ 54.3	$ 38.5	$ 177.8	$ 35.5	$ 35.4	$ 481.5	$ 823.0

(1) Includes outstanding principal amount at December 31, 2009. This table does not include future commitment fees, interest expense or other fees on these facilities because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) The 9.375% senior notes are due December 1, 2017.

(3) At December 31, 2009 we had three drilling rigs under contracts which expire in 2010. Any other rig performing work for us is doing so on a well-by-well basis and therefore can be released without penalty at the conclusion of drilling on the current well. Drilling obligations for individual wells have not been included in the table above. 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 based on our working interest.

Table of Contents

Drilling rig commitments do not include contingent commitments to drill wells on our unproved properties in order to retain oil and natural gas leasehold interests, including up to an estimated $625 million that we may be required to spend between January 1, 2009 and June 30, 2018 pursuant to the acquisition agreement relating to the purchase of our properties in the Appalachian Basin in 2008.

(4) Derivative instruments represent the fair value for interest rate derivatives presented as liabilities in our combined balance sheet as of December 31, 2009. The ultimate settlement amounts of our derivative liabilities are unknown because they are subject to continuing market fluctuations.

(5) 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.

In addition to amounts shown in the above table, we have entered into contracts with third party pipeline owners that provide firm processing rights and firm takeaway capacity on pipeline systems. The remaining terms on these contracts range from one to 14 years and require us to pay transportation demand and commodity charges regardless of the amount of pipeline capacity utilized by us.

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 combined 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 combined financial statements. See Note 2 of the notes to the audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Natural Gas and Oil Properties

Successful Efforts Method

Our natural gas 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 unit-of-production method as natural gas 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 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.

Table of Contents

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 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, 2008 and 2009 and the three months ended March 31, 2009 and 2010, we charged impairment expense for expired or expiring leases with a cost of $10.1 million, $54.2 million, $7.8 million and $2.3 million, respectively. The assessment of unevaluated natural gas 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 and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

Our independent engineers and internal technical staff prepare the estimates of natural gas and oil reserves and associated future net cash flows. Current accounting guidance allows only proved natural gas and oil reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of natural gas 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 and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas 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 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 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.

Impairment of Proved Properties

We review our proved natural gas 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 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

Table of Contents

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 during the years ended December 31, 2007, 2008 or 2009 or the three months ended March 31, 2009 and 2010.

New Accounting Pronouncements

SFAS No. 168, The FASB Accounting Codification and the Hierarchy of Generally Accepted Accounting Principles or SFAS 168 In July 2009, the Financial Accounting Standards Board ("FASB") issued SFAS 168 which will establish the Financial Accounting Standards Board Accounting Standards Codification (the "Codification") as the source of authoritative U.S. generally accepted accounting principles ("GAAP") recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases issued by the SEC are also sources of authoritative GAAP for SEC registrants.

SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51 or SFAS 160 codified in FASB ASC Topic 810 In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We have retroactively applied the provisions of this standard in these financial statements. The application of SFAS 160 did not affect our results of operations.

Revised Natural Gas and Oil Standard

In December 2008, the SEC released the final rule for Modernization of Oil and Gas Reporting, or Modernization. The Modernization disclosure requirements require reporting of natural gas and oil reserves using an average price based upon the prior 12 month period rather than year end prices and the use of new technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies are also allowed to disclose probable and possible reserves to investors in SEC filed documents. In addition, companies are required to report the independence and qualifications of their reserves preparer or auditors and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The Modernization disclosure requirements have become effective for the year ending December 31, 2009. The FASB has issued Accounting Standards Update 2010-03 (ASU 2010-03) "Extractive Industries Oil and Gas" to align its rules for oil and gas reserve estimation and disclosure requirements with the SEC's final rule. In October 2009, the SEC issued Staff Accounting Bulletin No. 113 (SAB No. 113), which revises portions of the interpretive guidance included in the section of the Staff Accounting Bulletin Series titled Topic 12: Oil and Gas Producing Activities. The principal changes involve revisions to bring Topic 12 into conformity with the contents of the Modernization. We have adopted the Modernization standard in the preparation of our December 31, 2009 oil and gas reserve estimates and related disclosures.

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

Commodity Price Risk and Hedges

For a discussion of how we use financial commodity swap contracts to mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, see " Commodity Hedging Activities."

Interest Rate Risks and Hedges

During the year end December 31, 2009, we had indebtedness outstanding under our $400 million senior secured revolving credit facility and $225.0 million under our second lien term loan facility, which bear interest at floating rates. The average annual interest rate incurred on this indebtedness for the years ended December 31, 2009 and 2008 was approximately 4.69% and 6.9%, respectively. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the year ended December 31, 2009 would have resulted in an estimated $5.3 million increase in interest expense for the year ended December 31, 2009 before giving effect to interest rate swaps. During the three months ended March 31, 2010, our indebtedness consisted primarily of fixed rate 9.375% senior notes due 2017 having an outstanding principal amount of $525 million.

Through interest rate derivative contracts, we have attempted to mitigate our exposure to changes in interest rates. We have entered into various variable to fixed interest rate swap agreements which hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. At March 31, 2010, we had an interest rate swap outstanding for a notional amount of $225 million with a fixed pay rate of 4.11% with a term expiring in July 2011. The $225.0 million swap relates to the floating rate second lien term loan, which was repaid in full with the net proceeds of the November 2009 senior notes offering. We did not terminate the interest rate swap related to the $225.0 million second lien term loan facility when it was repaid in November 2009; therefore, this swap does not currently have floating rate debt associated with it.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($139.9 million at March 31, 2010), joint interest receivables ($4.9 million at March 31, 2010) and the sale of our natural gas production ($22.6 million in receivables at March 31, 2010), 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. 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.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases.

Table of Contents

BUSINESS

Our Company

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and production of natural gas properties located onshore in the United States. We focus on unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. 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 existing acreage. As of December 31, 2009, our estimated proved reserves were 1,140.7 Bcfe, consisting of 1,130.3 Bcf of natural gas and 1.7 MMBbl of oil and condensate. As of December 31, 2009, 99% of our proved reserves were natural gas, 24% were proved developed and 69% were operated by us. From December 31, 2006 through December 31, 2009, we grew our estimated proved reserves from 87.0 Bcfe to 1,140.7 Bcfe. In addition, we grew our average daily production from 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. For the year ended December 31, 2009 and the three months ended March 31, 2010, we generated cash flow from operations of $149.3 million and $52.0 million, respectively, net income (loss) of $(106.2) million and $87.6 million, respectively, and EBITDAX of $201.3 million and $51.7 million, respectively. See "Selected Historical Combined 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 a large inventory of repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus Shale of the Appalachian Basin, the Woodford Shale of the Arkoma Basin (the Arkoma Woodford), the Fayetteville Shale of the Arkoma Basin and the Mesaverde tight sands and Mancos Shale of the Piceance Basin. From inception, we have drilled and operated 285 wells through December 31, 2009 with a success rate of approximately 98%. Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. For information on the possible limitations on our ability to drill our potential locations, see "Risk Factors Risks Relating to Our Business Our identified drilling 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 drilling locations."

We own two midstream systems (one in the Arkoma Basin and one in the Piceance Basin), and 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 and foreseeable production.

Our board of directors has approved a capital expenditure budget of up to $366 million for 2010, approximately 89% of which is allocated to drilling. Of our 2010 drilling budget, approximately 43% is allocated to the Appalachian Basin, 29% to the Arkoma Basin Woodford Shale and 28% to the Piceance Basin. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget based on liquidity, commodity prices and drilling results.

Table of Contents

We believe we have a conservative financial position characterized by modest leverage, a strong hedge position and ample liquidity. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending Deceember 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. On November 17, 2009, we completed an offering of $375 million principal amount of our 9.375% senior notes due 2017. On January 19, 2010, we completed an offering of $150 million additional principal amount of our 9.375% senior notes due 2017. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility.

Business Strategy

Our objective is to build value through consistent growth in estimated reserves and production on a cost-efficient basis while delineating future drilling locations. Our strategy is to emphasize internally generated drillbit growth on our potential drilling locations in low-risk, repeatable, unconventional resource plays. We have made significant investments in technical staff, acreage and seismic data and technology to build our drilling inventory. Our strategy has the following principal elements:

Concentrate on unconventional resources in core operating areas. We currently operate in three primary basins: the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. Concentrating our drilling and producing activities on unconventional resources in these core areas allows us to capitalize on the regional expertise that we have developed in interpreting specific geological and operating trends and optimizing drilling and completion techniques. Operating in multiple core areas allows us to optimize capital allocation between basins based on risked well economics to balance our portfolio and achieve consistent and profitable production and reserve growth.

Drive growth through low-risk development drilling in established resource plays. We expect to generate profitable, long-term reserve and production growth predominantly through repeatable, low-risk development drilling on our assets. We typically allocate the substantial majority of our drilling budget to our development and delineation projects. We have a multi-year drilling inventory and have over 16,000 potential drilling locations on our existing leasehold acreage. We have drilled 285 wells from inception through December 31, 2009 and have achieved an approximate 98% success rate.

Focus on cost efficiency. We believe concentrating on our sizeable oil and gas resources in place will allow us to consistently increase production. Our experience suggests that as we increase the density of development within our operating areas, we increase our expected recovery while reducing costs on a per well basis. We endeavor to control costs such that our cost to find, develop and produce natural gas is within the best performing quartile of our peer group based on publicly available information.

Maintain financial flexibility and conservative financial position. We typically use equity capital to fund land acquisitions, exploratory drilling and initial infrastructure, while using cash flow from operations and debt financing to fund our drilling program. We repaid our $225 million second lien term loan facility in full with proceeds from the November 2009 $375 million senior notes offering. In addition, we applied the net proceeds of $124 million from our November 2009 equity placements and applied the balance of the net proceeds from the November senior notes offering and the net proceeds of the January 2010 notes offering to reduce the outstanding balance under our senior secured revolving credit facility. As of May 12, 2010, after giving effect to the redetermination of the borrowing base under our senior secured revolving credit facility at

$400 million, we would have had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility, which, together with our operating cash flow, is expected to provide us with the financial flexibility to pursue our currently planned delineation and development drilling activities.

Manage commodity price exposure through an active hedging program. We maintain an active hedging program designed to mitigate volatility in commodity prices and regional basis differentials. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending December 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. Substantially all of our hedges are at regional sales points in our operating regions, which mitigates the risk of basis differential to the Henry Hub index.

Manage midstream assets and secure firm takeaway capacity. We own midstream systems in the Arkoma Woodford and Piceance Basin, which we believe enhance the efficiency of our drilling operations in those areas. We believe access to gathering and processing infrastructure allows us to decrease dependence on third parties, better manage the timing of our development and optimize the markets to which we sell our production. We expect that our midstream assets will accommodate our anticipated drilling program, resulting in an increase in our throughput volumes and operating cash flows. In addition, we believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction to accommodate our existing and foreseeable production.

Business Strengths

We believe we have the following strengths:

Proven track record of efficient production and reserve growth. We have a proven track record of growth in our production and estimated proved reserves. For example, we grew our production from an average of 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. In addition, we have grown our estimated proved reserves from 87.0 Bcfe at December 31, 2006 to 1,140.7 Bcfe at December 31, 2009.

Multi-year, low-risk, development drilling inventory. Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. From inception in 2004 through December 31, 2009, we have drilled and operated 285 wells, achieving an approximate 98% success rate. Our concentrated leasehold position has been delineated largely through drilling done by us as well as other industry players, which we believe will help us to achieve predictable and repeatable future well results and minimize investment risk.

Control over operating decisions and capital program. As of December 31, 2009, we had a net leasehold interest of 61.4% on our acreage and operated 67% of our production. Our high percentage of operated wells allows us to effectively control operating costs, timing of development activities, application of technological enhancements, marketing of production and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary, which allows us a significant degree of flexibility to adjust the size and timing of our development in response to changes in market conditions.

Proven executive management team with track record of value creation. We believe our management team's experience and expertise in the Midcontinent and Rocky Mountain operating regions coupled with our multiple resource plays provides a distinct competitive

Table of Contents

advantage. Our eight corporate officers have an average of 25 years of industry experience in the Midcontinent and Rocky Mountain operating regions and have successfully built, grown and sold three unconventional resource-focused companies in the past 20 years. Our Chairman and Chief Executive Officer and our President and Chief Financial Officer and many other members of our management team worked together as managers or executives while at Amoco, Barrett Resources, Pennaco Energy, Inc. or Antero Resources Corporation, a former affiliate of our company that operated in the Barnett Shale and was sold to XTO Energy in 2005.

Leading technical team with significant unconventional shale and tight sand experience. All of our proved reserves and resources are classified as unconventional resources, including fractured shale gas plays and basin-centered tight gas. Since 2003, our technical team has drilled and operated over 200 horizontal and over 150 vertical wells in the Barnett, Woodford and Marcellus shales and over 150 directional wells in the Piceance tight sands. Our technical team has significant experience in drilling horizontal and directional wells in addition to fracture stimulation of unconventional formations. We utilize the latest geologic, drilling and completion technologies to increase the predictability and repeatability of finding and recovering resources in these unconventional gas plays. We were an early user of microseismic imaging to monitor frac performance in real time, completed one of the first simul-fracs stimulating three horizontal wells simultaneously in the Barnett Shale and have drilled some of the longest lateral shale gas wells completed to date.

Strong sponsor support. We are backed by a number of well known financial sponsors, including Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners. To date, our equity investors have made total equity investments of approximately $1.4 billion, including our November 2009 $125 million equity placements.

Our Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared by our independent reserve engineering firms or by our internal reserve engineers, as applicable, in accordance with the rules and regulations of the SEC applicable to the periods presented. In this prospectus, we have only included estimates of our proved reserves and have not included any estimates of probable or possible reserves that may exist.

New SEC Rules

In December 2008, the SEC adopted new rules related to modernizing reserve calculations and disclosure requirements for oil and natural gas companies, which became effective for annual reporting periods ending on or after December 31, 2009. The most significant amendments to the requirements included the following:

Commodity Prices Economic producibility of reserves and discounted cash flows are now determined using the unweighted arithmetic average of the first-day-of-the-month commodity prices over the preceding 12-month period unless contractual arrangements designate a different price to be used.

Disclosure of Unproved Reserves Probable and possible reserves may be disclosed separately on a voluntary basis.

Proved Undeveloped Reserve Guidelines Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

Reserves Estimation Using New Technologies Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

Reserves Personnel and Estimation Process Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

Non-Traditional Resources The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted these new rules effective December 31, 2009 as required by the SEC.

Application of the new reserve rules resulted in the use of 12-month average prices, which were lower at December 31, 2009 for both oil and gas than the prices we would have used under the previous rules, under which we would have used prices at such date. This resulted in a decrease in some of our proved reserves due to pricing when compared to what our proved reserves would have been at December 31, 2009 using prices at such date. This decrease was offset by our ability to include additional undrilled locations offsetting producing wells in our estimation of our proved reserves under the new rules.

Other Changes to Proved Reserves Presentation

Beginning with the year ended December 31, 2009, we recognized proved reserves from properties having a positive undiscounted net estimated future cash flow as opposed to our practice in prior years of including properties within our proved reserves only if their cash flow was positive using a discount rate of 10% (PV-10). This change is consistent with the SEC definitions of "economic producability" and "proved oil and gas reserves" and consistent with what we believe to be the common practice of the oil and gas industry. Accordingly, the estimated proved reserves as of December 31, 2009 included in this prospectus have been prepared using a different methodology than that used to prepare our estimated proved reserves as of December 31, 2007 and 2008 included in this prospectus. The effect of this change resulted in increased estimated proved reserve volumes as of December 31, 2009 of approximately 138 Bcfe over our estimated proved reserves as of December 31, 2008 and also had the effect of reducing our standardized measure of discounted future net cash flows.

Reserves Presentation

The following table summarizes our estimated proved reserves and related PV-10 at December 31, 2007, 2008 and 2009. All of our proved reserves have been estimated by our independent reserve engineers. Our estimated proved reserves are located in the Appalachian Basin, the Arkoma Basin Woodford Shale, the Piceance Basin and the Fayetteville Shale and are based on reports from Wright & Company, Inc., DeGolyer and MacNaughton ("D&M"), Ryder Scott & Company, L.P. and D&M, respectively. We refer to these firms collectively as our independent engineers. Our independent engineers estimated 100% our our proved reserves in each applicable basin as of December 31, 2009. Copies of the summary reports of our independent engineers with respect to each of our operating basins as of December 31, 2009 are filed as Exhibits 99.1 through 99.4 to the registration statement of

Table of Contents

which this prospectus forms a part. The information in the following table does not give any effect to or reflect our commodity hedges.

	At December 31,		
	2007	2008	2009
Estimated proved reserves:			
Natural gas (Bcf)	228.7	672.2	1,130.3
Oil and condensate (MMBbl)	1.0	1.2	1.7
Total estimated proved reserves (Bcfe)	234.7	679.6	1,140.7
Proved developed producing (Bcfe)	98.9	238.1	247.0
Proved developed non-producing (Bcfe)	10.2	0.7	28.6
Proved undeveloped (Bcfe)	125.6	440.8	864.9
Percent developed	46.5%	35.1%	24.2%
PV-10 (in millions)(1)	$ 425.9	$ 649.1	$ 244.8
Standardized measure (in millions)(1)	$ 432.1	$ 688.6	$ 235.1

(1) PV-10 was prepared using prices in effect at the end of the periods presented, discounted at 10% per annum, without giving effect to taxes. PV-10 may be considered 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 prices 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.

The following table sets forth the estimated future net cash flows, contracts, from proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows (PV-10), and the prices used in projecting future net cash flows at December 31, 2007, 2008 and 2009:

	At December 31,		
(In millions, except per Mcf data)	**2007(1)**	**2008(2)**	**2009(3)**
Future net cash flows	$ 972.3	$ 1,695.6	$ 1,362
Present value of future net cash flows:			
Before income tax (PV-10)	$ 425.9	$ 649.1	$ 244.8
After income tax (Standardized measure)	$ 432.1	$ 688.6	$ 235.1

(1) Spot prices used at December 31, 2007 were $6.22 per Mcf for the Arkoma Basin and $6.04 per Mcf for the Piceance Basin.

(2) Spot prices used at December 31, 2008 were $4.61 per Mcf for the Arkoma Basin and $4.61 per Mcf for the Piceance Basin.

(3) Average prices used at December 31, 2009 were $3.25 per Mcf for the Arkoma Basin, $3.07 per Mcf for the Piceance Basin and $4.15 per Mcf for the 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). Such calculations for 2007 and 2008 are based on costs and prices in effect at December 31 of each year, without escalation. In accordance with the new SEC rules, prices for 2009 were based on a 12-month average, without escalation. There can be no assurance that the proved reserves will be produced

within the periods indicated or that 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.

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2009, as estimated by our independent engineers, were 864.9 Bcfe, over 99% of which consisted of natural gas. Changes in proved undeveloped reserves that occurred during the year were due to:

- conversion of 3.2 Bcfe of proved undeveloped reserves into proved developed reserves;
- addition of new proved undeveloped reserves of 754.0 Bcfe, including approximately 138 Bcfe attributable to our decision to recognize proved reserves from properties having a positive undiscounted net estimated future cash flow; and
- negative revision of 326.8 Bcfe in proved undeveloped reserves due to lower commodity prices and performance revisions.

Estimated future development costs relating to the development of our proved undeveloped reserves are approximately $1,389.2 million. All of our proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2014.

Preparation of Reserve Estimates

Our proved reserve estimates as of December 31, 2009 included in this prospectus relating to our properties in the Arkoma Basin Woodford Shale, the Fayetteville Shale, the Piceance Basin and the Appalachian Basin were prepared by our independent engineers in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their geographic expertise and their historical experience in engineering certain properties. The technical persons at each independent reserve engineering firm responsible for preparing the reserves 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.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent engineers in their reserves estimation process. Throughout the year, our technical team meets on a regular basis with each independent engineer to review properties and discuss methods and assumptions used by such firms in their respective preparations of our year-end reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, preliminary copies of each independent engineer's reserve reports are reviewed by our internal technical staff with representatives of such firms. The independent engineers' reserve estimates and related reports are reviewed and approved by our Vice President of Production, Kevin J. Kilstrom. 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. 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

Table of Contents

independent engineers' reserve estimates and related reports with 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 and natural gas, 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, each independent engineer 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, well test data.

Production, Revenues and Price History

Natural gas is a commodity. The price that we receive for the natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States has increased dramatically during this decade; however, the current economic slowdown reduced this demand during the second half of 2008 and through 2009. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. 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.

The following table sets forth information regarding our production for each field containing 15% or more of our total estimated proved reserves and our total production, and regarding our revenues and realized prices and production costs for the years ended December 31, 2007, 2008 and 2009. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,		
	2007	2008	2009
Production data:			
Natural gas (Bcf):			
Arkoma	6.2	18.6	23.4
Piceance	4.7	11.7	11.2
Appalachia			0.5
Total	10.9	30.3	35.1

	Year Ended December 31,		
	2007	2008	2009
Oil (MBbl):			
Arkoma	15.3	20.5	26.7
Piceance	34.1	94.4	87.3
Appalachia			
Total	49.4	114.9	114.0
NGLs (Bcfe)(1)		0.9	2.6
Total combined production (Bcfe)	11.2	31.9	38.4
Daily combined production (MMcfe/d)	30.8	87.4	105.2
Gas and oil production revenues (in millions)	$ 67.7	$ 229.7	$ 129.6
Average prices before effects of hedges (per Mcfe)(2)	$ 6.03	$ 7.41	$ 3.62
Average realized prices after effects of hedges (per Mcfe)(2)	$ 6.65	$ 8.25	$ 6.88
Average costs per Mcfe:			
Lease operating costs	$ 0.39	$ 0.43	$ 0.49
Gathering, compression and transportation	$ 0.89	$ 0.94	$ 0.79
Production taxes	$ 0.20	$ 0.33	$ 0.14
Depreciation, depletion, amortization and accretion	$ 4.46	$ 4.03	$ 3.91
General and administrative	$ 1.04	$ 0.52	$ 0.58

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(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.

Productive Wells

As of December 31, 2009, we had a total of 792.0 gross (304.0 net) producing wells averaging a 37.8% working interest.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we own an interest as of December 31, 2009. A majority of our developed acreage is subject to mortgage liens securing our revolving credit facility. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

Developed Acres		Undeveloped Acres		Total Acres		Percent Leasehold Interest
Gross	Net	Gross	Net	Gross	Net	
132,416	61,796	338,513	227,354	470,929	289,150	61.4%

Table of Contents

Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of December 31, 2009 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
2010	82,948	33,122
2011	70,477	26,417
2012	12,806	7,965

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2007, 2008 and 2009. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Year Ended December 31,					
	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	36.0	17.5	38.0	25.4	35.0	4.8
Dry			1.0	0.8		
Total development wells	36.0	17.5	39.0	26.2	35.0	4.8
Exploratory wells:						
Productive	152.0	51.7	297.0	80.1	125.0	19.9
Dry	4.0	1.0	2.0	0.6	1.0	0.08
Total exploratory wells	156.0	52.7	299.0	80.7	126.0	19.98

Our Core Operating Areas

Appalachian Basin Marcellus Shale

Our properties in the Appalachian Basin are principally located in southwest Pennsylvania and northern West Virginia. As of December 31, 2009, we had approximately 119,000 net leasehold acres in the Appalachian Basin, 87% of which was held by production. All of this acreage includes Marcellus Shale rights.

Since spudding our first well in the Appalachian Basin in March 2009, through December 31, 2009 we have completed a total of 4 gross (4 net) horizontal wells and 1 gross (1 net) vertical well in the area. We are currently operating three drilling rigs in the Appalachian Basin. As of December 31, 2009, we had 2,124 potential drilling locations in the area.

Our first two wells in the Marcellus Shale of the Appalachian Basin were brought online in August 2009, and three additional wells were brought online in December 2009.

Approximately 43% of our 2010 drilling budget has been allocated to the Appalachian Basin.

Arkoma Basin Woodford Shale

Our properties in the Arkoma Woodford are located in eastern Oklahoma. As of December 31, 2009, we had approximately 84,000 net leasehold acres in the area, 61% of which was held by

Table of Contents

production. For the year ended December 31, 2009, we had 60.5 MMcfe/d of average daily production in the area, including NGLs retained by our midstream business.

Our activity in the Arkoma Woodford has consisted of a combination of exploratory, step-out and development drilling designed both to secure acreage and to delineate areas of economic production for further development. As of December 31, 2009, we had a total of 482 gross (122 net) producing wells in the area. We are currently operating one drilling rig in the Arkoma Woodford and, as of December 31, 2009, had 4,693 gross potential drilling locations in the area.

During 2007, we and the industry began to develop this area using alternative spacing to determine the optimum density for development. These results indicate that 80-acre spacing is economically feasible on much of our acreage. In addition, we have reduced our average cost per lateral foot drilled during 2009 through improved mud systems, optimal bit selections, operational efficiencies and reduced drilling day rates. Our development efforts to date have also successfully demonstrated that we are able to drill and complete wells across minor faults that previously limited the length of our lateral drilling.

Approximately 29% of our 2010 drilling budget has been allocated to the Arkoma Basin Woodford Shale.

Piceance Basin

Our properties in the Piceance Basin are located on the western slope of Colorado. As of December 31, 2009, we had approximately 60,000 net leasehold acres in the area.

Since drilling our first well in the Piceance Basin in 2006 and through December 31, 2009, we have operated and completed 185 gross (154.7 net) producing directional wells in the area. For the year ended December 31 2009, we completed 12 gross (6.9 net) directional wells in this area. We had average production of 32.2 MMcfe/d for the year months ended December 31, 2009. We are currently operating one drilling rig and one completion rig in the Piceance Basin and, as of December 31, 2009, had 7,821 potential drilling locations in the area.

We believe we are well positioned to take advantage of the significant opportunities we have identified in the development of the Mesaverde tight sands and the Mancos Shale in the Piceance Basin. We initiated a drilling pilot to evaluate potential Mancos Shale reserves in January 2008. This pilot was designed to test productivity and evaluate the economics of low permeability lithologies of the Mancos/Niobrara petroleum system. We have received formal approval from the Colorado Oil & Gas Commission for 10-acre density for Mancos/Niobrara on 7,000 acres. We also received approval to commingle our Mancos Shale production with production from the overlying Mesaverde tight sand formation, which we believe will enhance our economic returns in this area.

Approximately 28% of our 2010 drilling budget has been allocated to the Piceance Basin.

Other Operating Areas

Fayetteville Shale

As of December 31, 2009, we held approximately 6,000 net acres in the eastern part of the Fayetteville Shale. We had average production of 4.0 MMcfe/d for the year ended December 31, 2009. We have 83 gross (5.3 net) wells currently on production. We do not operate wells in the Fayetteville Shale but participate in wells operated by others.

Table of Contents

Our Midstream Operations

Arkoma Midstream System

We own 60% of Centrahoma Processing LLC, a joint venture that operates two cryogenic processing plants in the Arkoma Basin. The remaining 40% interest in Centrahoma is owned by MarkWest. These plants are currently running at or near their operational capacity of 100 MMcf/d, yield 8,000 to 9,000 gross Bbl/d of NGLs and are capable of yielding NGLs of up to 4.0 gallons per Mcf. Due to capacity constraints at these plants, we are in the early stages of a plant capacity expansion plan for 2011. All of our and the majority of Newfield Exploration's wet gas in the Woodford Play is processed at these plants under long term contracts. In addition, the ONEOK NGL pipeline, which both of our plants deliver NGL products into, became operational in September 2008.

We own and operate an amine treating plant for CO_2 removal in the East Rockpile area of the Arkoma Woodford. This plant is located in one of our key drilling areas, has 42 MMcf/d capacity and is currently running at 25 MMcf/d.

We also own approximately 50 miles of gathering pipeline in the Northern Front and East Rockpile areas of the Arkoma Woodford.

In April 2010, we began a process to consider a sale of our Arkoma Woodford midstream assets. We have not yet entered into a definitive agreement with respect to this sale, and we cannot be certain that any definitive agreement will be entered into or that any sale transaction will be consummated.

Piceance Gathering System

We own approximately 20 miles of gathering pipeline in the Gravel Trend in the Piceance Basin. We do not currently own or operate any compression facilities in the area. Our gas is gathered and delivered to third parties for compression, processing and takeaway.

Takeaway Capacity

Arkoma Basin

We currently have firm takeaway capacity of 20 MMcf/d on the Ozark Gas Transmission Pipeline through August 2012 and 20 MMcf/d of firm takeaway capacity on the Boardwalk Gulf Crossing Pipeline through July 2014. We have also contracted for 10 MMcf/d of additional takeaway capacity on the Boardwalk Gulf Crossing Pipeline to begin in August 2010 and another 10 MMcf/d of additional takeaway capacity to begin in August 2011, with both contracts having five-year terms.

Piceance Basin

We currently have 40MMcf/d of firm takeaway capacity on the WIC Pipeline through September 2020. The El Paso WIC Pipeline expansion from Meeker, Colorado to Opal, Wyoming will provide 230 MMcf/d of incremental capacity to more liquid markets. Additionally, we have contracted for 25 MMcf/d of firm takeaway capacity for 10 years on the El Paso Ruby Pipeline that has applied to FERC for authorization to commence construction. The Ruby Pipeline will begin in Opal, Wyoming and is expected to provide approximately 1.3 Bcf/d of incremental pipeline capacity to the Northwest and West Coast of the United States beginning in 2011.

Appalachian Basin

We have 40 MMcf/d of firm transportation on the Columbia Pipeline from August 2009 for 7.5 years. In April 2010, we added an additional 110 MMcf/d of firm transportation capacity on the Columbia Pipeline, of which 70 MMcf/d is scheduled to begin in August 2010 and the remaining

Table of Contents

40 MMcf/d is scheduled to begin in April 2011. Our contract for this additional capacity runs through March 2021.

Corporate Sponsorship and Structure

We began operations in 2004, and have funded development and operating activities of each of the operating subsidiaries primarily through equity capital raised from private equity sponsors and institutional investors, through borrowings under our bank credit facilities and through internal operating cash flows. Our primary private equity sponsors are affiliates of Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners.

Antero Resources LLC was formed as a holding company in October 2009 in connection with our November 2009 corporate reorganization of the operating subsidiaries and the issuance of a new class of units. Prior to this reorganization, all of our operations were conducted by five separately capitalized commonly controlled operating subsidiaries.

In connection with the November 2009 corporate reorganization, the stockholders of each of the operating subsidiaries contributed all of the outstanding shares of each operating subsidiary to Antero. In return, Antero issued an equivalent number of units of different classes to such stockholders. The newly issued units are substantially similar in character to the contributed stock of each operating subsidiary, including the relative priority of any distributions made by Antero as well as the vesting schedule applicable to shares held by any member of management. Simultaneously with this exchange, Antero issued a new class of units in exchange for $110 million in new equity capital. Later in November 2009, Antero issued additional units of such new class in exchange for an additional $15 million in new equity capital.

None of Antero's outstanding units are entitled to current cash distributions or are convertible into indebtedness, and Antero has no obligation to repurchase these units at the election of the unitholders. Although Antero is required to make quarterly distributions to cover any income taxes allocated to each unitholder, the unitholders have no other rights to cash distributions (except in the case of certain liquidation events). We do not anticipate making any such tax distributions in the foreseeable future. Pursuant to the terms of Antero's limited liability company agreement, upon certain liquidation events, units held by our private equity sponsors and institutional investors are entitled to receive, prior to any amounts received by other unitholders, an amount equal to the initial purchase price of such units plus a special distribution with respect to such units and will continue to participate on a pro rata basis with other unitholders in any excess funds available in liquidation. For more information on the terms of the Antero limited liability company agreement, see "Management Certain Relationships and Related Party Transactions."

Concurrent with the closing of the reorganization, Antero issued profits interests to Antero Resources Employee Trust, LLC, a newly formed Delaware limited liability company, owned solely by certain of our officers and employees. These profits interests only participate in distributions upon liquidation events meeting certain requisite financial return thresholds. In turn, Antero Resources Employee Trust issued similar profits interests to certain of our officers and employees.

We used the aggregate net proceeds of approximately $124 million from the November 2009 equity placements to repay borrowings outstanding under our senior secured revolving credit facility.

Table of Contents

The following diagram shows our organizational structure after giving effect to the November 2009 corporate reorganization:

The issuer was formed in October 2009 as an indirect wholly owned subsidiary of Antero. The issuer was formed to arrange financing for Antero and the operating subsidiaries, including the notes offered hereby. The indenture governing the notes limits the issuer's activity to those of a finance subsidiary. The issuer does not own any significant assets other than intercompany obligations.

The payment of the principal, premium and interest on the notes is fully and unconditionally guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than the issuer) and certain of its future restricted subsidiaries. Centrahoma Processing LLC is a joint venture owned 60% by Antero and 40% by MarkWest Energy Partners, L.P. and does not guarantee the notes. As of March 31, 2010, Centrahoma Processing LLC, had no outstanding indebtedness and held less than 4% of our consolidated total assets. The guarantees are unsecured senior indebtedness of the guarantors and have the same ranking with respect to the guarantors' indebtedness as the notes have with respect to the issuer's indebtedness. See "Description of Notes Guarantees."

Marketing and Major Customers

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 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 ranging anywhere from one day to seven 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. However, based on the current demand for natural gas 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. For a list of our

Table of Contents

customers that accounted for 10% or more of our natural gas revenues during the last two calendar years, see "Note 2(p) Concentrations of Credit Risk" in our audited consolidated financial statements for the years ended December 31, 2009, 2008 and 2007 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.

In addition, the acquisition agreement relating to the purchase of our properties in the Appalachian Basin in 2008 contains various drilling commitments that may require us to spend up to an estimated $625 million between January 1, 2009 and June 30, 2018 at structured intervals. If we do not fulfill our drilling commitments, title to portions of the properties we purchased may revert to the seller, which could have a material adverse effect on our future business and results of operations.

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. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other natural gas operations in certain areas of the Rocky Mountain region. 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.

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 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, 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. 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 a number of 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

Table of Contents

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 eliminated and replaced by a structure under which pipelines provide transportation and storage service on an 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 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, EP Act 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 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 EP Act 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 beginning in 2009, 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. Requests for clarification and rehearing of Order 720 have been filed at FERC and a decision on those requests is pending.

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 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.

Table of Contents

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 Matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing 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 commences, restrict the types, quantities and concentrations of various substances that can be released 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 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.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, or 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

Table of Contents

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 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.

Waste Handling

We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA"), which imposes requirements related to the generation, transportation, treatment, storage, handling, disposal and clean-up of solid and hazardous wastes and the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil, natural gas, or geothermal energy constitute "solid wastes," which are regulated under the less stringent, non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes."

We believe that we are in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we held all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of natural gas and oil exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other 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 same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development. 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 maintain all required discharge permits necessary to conduct our operations, and we 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, the costs of which are not expected to be substantial.

Air Emissions

The Federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions.

While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission-related issues, we do not believe that such requirements will have a material adverse effect on our operations. Obtaining permits has the potential to delay the development of natural gas and oil projects. We believe that we are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations.

Regulation of "Greenhouse Gas" Emissions

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" (GHGs) and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere and other climatic changes. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of GHGs. One bill approved by the U.S. House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, or ACESA, would require an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050. Similar bills are presently pending before the U.S. Senate. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved.

In addition, in December 2009, the U.S. Environmental Protection Agency, or the EPA, determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule became effective in March 2010 but it does not require immediate reductions in GHG emissions. The stationary source rule was adopted in May 2010 but it does not become effective until January 2011 and is the subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

Table of Contents

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal natural gas and oil leases in areas where certain species that are listed as threatened or endangered and where other species, such as the sage grouse, potentially could be listed as threatened or endangered under the ESA exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for natural gas and oil development. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2009, nor do we anticipate that such expenditures will be material in 2010.

Legal Matters

We are a named defendant in certain lawsuits arising in the ordinary course of business. While the outcome of lawsuits against us cannot be predicted with certainty, our management team does not expect these matters to have a material adverse impact on our financial statements.

In May 2008, we received a notice of violation from the Colorado Department of Public Health and Environment, or CDPHE, that alleged that our construction of a pipeline in Garfield County, Colorado was not in compliance with CDHPE's general permit for stormwater discharges associated with construction activities. The notice of violation was based on an inspection of the construction area by CDHPE in May 2007. Although we believe that we corrected any deficiencies promptly after the inspection, CDHPE has proposed a fine of $157,233 for the alleged violations. We are currently engaged in discussions with CDHPE in an effort to resolve this matter.

In February 2009, we received a grand jury subpoena from the U.S. Environmental Protection Agency regarding an alleged unauthorized discharge at a well site near Atoka, Oklahoma in May 2007. Based on information presently available to us, it appears that well fracturing fluids stored by a third party contractor in a tank leaked into a surrounding berm and were later discharged along with rainwater into a nearby waterway. The site was being managed by the contractor at the time of the incident. We have provided the information that was requested by the subpoena. No claim has been made against us with respect to this matter to date, and, based on information presently available to us, we do not believe that our company is a target of the investigation.

Employees

As of December 31, 2009, we had 56 full-time employees, including nine in geology, 12 in production and engineering, 13 in accounting and administration, 17 in land, three in midstream and two senior executives. We also employed a total of 53 contract personnel who assist our full-time employees with respect to specific tasks and 73 outside lease brokers. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

MANAGEMENT

Executive Officers and Directors

The following table sets forth names, ages and titles of our executive officers and directors. Each of the individuals listed below holds the position stated below at each of the issuer, Antero and each operating subsidiary.

Name	Age	Title
Peter R. Kagan(1)	42	Director
W. Howard Keenan, Jr.(1)	59	Director
Christopher R. Manning(1)	42	Director
Paul M. Rady	56	Chairman of the Board of Directors and Chief Executive Officer
Glen C. Warren, Jr.	54	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	55	Vice President Production
Robert E. Mueller	53	Vice President Geology
Brian A. Kuhn	51	Vice President Land
Mark D. Mauz	52	Vice President Gathering, Marketing and Transportation
Steve M. Woodward	51	Vice President Business Development
Alvyn A. Schopp	51	Vice President Accounting & Administration and Treasurer
Kathryn S. Wilson	35	General Counsel and Assistant Secretary

(1) Member of the Audit Committee and the Compensation Committee.

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Our officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or principal officers.

Peter R. Kagan has served as a director since 2004. Mr. Kagan has been with Warburg Pincus since 1997 and co-leads the firm's investment activities in energy and natural resources. He is also a member of the firm's Executive Management Group. Mr. Kagan received an A.B. degree cum laude from Harvard College and J.D. and M.B.A. degrees with honors from the University of Chicago. Prior to joining Warburg Pincus, he worked in investment banking at Salomon Brothers in both New York and Hong Kong. Mr. Kagan currently also serves on the boards of directors of Broad Oak Energy, Fairfield Energy, Laredo Petroleum, MEG Energy, Resources for the Future, Targa Resources and Targa Resources Partners L.P. In addition, he is a member of the Visiting Committee of the University of Chicago Law School.

W. Howard Keenan, Jr. has served as a director since 2004. Mr. Keenan has over thirty years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private equity investment manager focused on the energy industry. Mr. Keenan currently serves on the Board of Directors of Concho Resources Inc. and GeoMet, Inc. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas, including the founding of the first Yorktown Partners fund in 1991. He is serving or has served as a director of multiple Yorktown Partners portfolio companies. Mr. Keenan holds an A.B. degree cum laude from Harvard College and an M.B.A. degree from Harvard University.

Christopher R. Manning has served as a director since 2005. Mr. Manning is a Partner of Trilantic Capital Partners, or TCP. Mr. Manning joined TCP in 2009. He was concurrently the Head of Lehman Brothers' Investment Management Division, including both the Asset Management and Private Equity businesses, in Asia-Pacific from 2006 to 2008. He was also a member of the Investment Management Division Global Operating Committee and the Private Equity Division Operating Committee. Lehman Brothers Holdings Inc. filed a voluntary petition for protection under the U.S. bankruptcy code in September 2008. Prior to joining TCP, Mr. Manning was the chief financial officer of The Wing Group, a developer of international power projects. Prior to The Wing Group, he was in the investment

Table of Contents

banking department of Kidder, Peabody & Co., where he worked on M&A and corporate finance transactions. Mr. Manning also currently serves on the boards of Enduring Resources, The Cross Group and Mediterranean Resources. He holds an M.B.A. from The Wharton School of the University of Pennsylvania and a B.B.A. from the University of Texas at Austin.

Paul M. Rady has served as Chief Executive Officer and Chairman of the Board of Directors since May 2004. Mr. Rady also served as Chief Executive Officer and Chairman of the Board of Directors of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Prior to Antero Resources Corporation, Mr. Rady served as President, CEO and Chairman of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Prior to Pennaco, Mr. Rady was with Barrett Resources from 1990 until 1998 where he initially was recruited as Chief Geologist in 1990, then served as Exploration Manager, EVP Exploration, President, COO and Director and ultimately CEO. Mr. Rady began his career with Amoco where he served 10 years as a geologist focused on the Rockies and Mid-Continent. Mr. Rady is the managing member of Salisbury Investment Holdings, LLC. Mr. Rady holds a B.A. in Geology from Western State College of Colorado and M.Sc. in Geology from Western Washington University.

Glen C. Warren, Jr. has served as President, Chief Financial Officer and Secretary and as a director since May 2004. Mr. Warren also served as President and Chief Financial Officer and as a director of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Prior to Antero Resources Corporation, Mr. Warren served as EVP, CFO and Director of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Mr. Warren spent 10 years as a natural resources investment banker focused on equity and debt financing and M&A advisory with Lehman Brothers, Dillon Read and Kidder Peabody. Mr. Warren began his career as a landman in the Gulf Coast region with Amoco, where he spent six years. Mr. Warren is the managing member of Canton Investment Holdings, LLC. Mr. Warren holds a B.A. from the University of Mississippi, a J.D. from the University of Mississippi School of Law and an M.B.A from the Anderson School of Management at U.C.L.A. Mr. Warren has served as a director of Diamond Foods, Inc. since 2005 and served as a director of Venoco Inc. from 2005 to 2008.

Kevin J. 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. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University.

Robert E. Mueller has served as Vice President of Geology since April 2005. Mr. Mueller also served as Chief Geologist of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Prior to Antero Resources Corporation, Mr. Mueller was with Williams as a Director of the Raton Basin asset team in 2001 to 2002. Mr. Mueller was Chief Geologist at Barrett Resources from 1996 to 2001. Mr. Mueller worked as a Senior Geologist for North American Resources from 1993 to 1996 after working the prior 11 years for Amoco Production Company. Mr. Mueller holds a B.S. in Geology from Northern Arizona University and an M.S. in Geology from the University of Wyoming.

Brian A. Kuhn has served as Vice President of Land since April 2005. Mr. Kuhn also served as Vice President of Land of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. From 2001 to 2002, Mr. Kuhn served as Head of Denver Land Department for Marathon Oil. Mr. Kuhn was the Vice President Land at Pennaco Energy from 1998 to 2001. Mr. Kuhn was a Division Landman with Barrett Resources from

Table of Contents

1993 to 1998. Mr. Kuhn was a Landman with Amoco for 13 years prior to 1993. Mr. Kuhn holds a B.B.A. in Petroleum Land Management from the University of Oklahoma.

Mark D. Mauz has served as Vice President of Gathering, Marketing and Transportation since April 2006. From 1993 to 2006, Mr. Mauz was with Duke Energy Field Services, most recently as its Managing Director of the Rockies Region. Mr. Mauz spent from 1990 to 1993 with Amoco in natural gas marketing and 9 years prior to 1990 as a Landman. Mr. Mauz holds a B.S. in Business from the University of Colorado.

Steven M. Woodward has served as Vice President of Business Development since April 2005. Mr. Woodward also served as Vice President of Business Development of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. From 1993 until 2002, Mr. Woodward was in senior business/project development roles with Dynegy. From 1990 to 1992, Mr. Woodward was with Reliance Pipeline Company as a Manager of Business Development. From 1988 to 1990, Mr. Woodward was at Western Gas Resources in a Business Development role. From 1981 to 1988, Mr. Woodward was with ARCO Oil & Gas Company in various engineering roles. Mr. Woodward holds a B.S. in Mechanical Engineering from the University of Colorado.

Alvyn A. Schopp has served as Vice President of Accounting and Administration and Treasurer since January 2005. Mr. Schopp also served as Controller and Treasurer from 2003 to 2005 and as Vice President of Accounting and Administration and Treasurer of our predecessor company, Antero Resources Corporation, from January 2005 until its ultimate sale to XTO Energy, Inc. in April 2005. From 2002 to 2003, Mr. Schopp was an Executive and Financial Consultant with Duke Energy Field Services. From 1993 to 2000, Mr. Schopp was CFO, Director and ultimately CEO of T-Netix. From 1980 to 1993 Mr. Schopp was with KPMG, most recently as a Senior Manager. Mr. Schopp holds a B.B.A. from Drake University.

Kathryn S. Wilson has served as General Counsel and Assistant Secretary since March 2010. From September 2001 to February 2010, Ms. Wilson was an associate with Vinson & Elkins L.L.P. specializing in securities offerings and mergers and acquisitions. Ms. Wilson holds a B.A. from Wesleyan University and a J.D. from the University of Texas School of Law.

Executive Compensation and Other Information

Compensation Discussion and Analysis

Introduction

This Compensation Discussion and Analysis (1) provides an overview of our compensation policies and programs; (2) explains our compensation objectives, policies and practices with respect to our executive officers; and (3) identifies the elements of compensation for each of the individuals identified in the following table, who we refer to in this Compensation Discussion and Analysis as our "Named Executive Officers."

Name	Principal Position
Paul M. Rady	Chairman of the Board of Directors and Chief Executive Officer
Glen C. Warren, Jr.	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	Vice President Production
Robert E. Mueller	Vice President Geology
Alvyn A. Schopp	Vice President Accounting and Administration

Table of Contents

Each of our Named Executive Officers is an employee of Antero Resources Corporation, which is a wholly owned subsidiary of Antero and one of the parent companies of the issuer. Prior to the November 2009 corporate reorganization, the Compensation Committee of the Board of Directors of Antero Resources Corporation approved all compensation decisions for our officers. Since the reorganization, the Compensation Committee of the Board of Directors of Antero, or the Board of Directors of Antero, as appropriate, has approved all compensation decisions for our officers. The Antero Board of Directors and the Antero Resources Corporation Board of Directors are comprised of the same members.

Compensation Philosophy and Objectives of Our Compensation Program

Since our inception in 2002, we have sought to grow our privately held, independent oil and gas company and our compensation philosophy has been primarily focused on recruiting individuals who would be motivated to help us achieve that goal. As a result, from our inception to September 2009, our executive compensation program was primarily designed to attract, retain and motivate our employees by compensating them with significant amounts of equity relative to cash compensation. In particular, we kept our executive officers' total cash compensation at levels that we believed were sufficient to provide them, in the case of salary amounts, with a modest amount of cash that provided them with an adequate means to support their families and, in the case of annual bonus amounts, discretionary amounts that rewarded them for overall individual performance during the year relative to continually evolving company objectives. With respect to non-cash awards, we have historically provided disproportionately greater amounts of equity, which we believed would ultimately compensate our executive officers as they participated in growing our company and maximizing stakeholder value. We also provided additional opportunities for our executive officers to purchase various classes of preferred and common shares in our company on the same basis as our institutional private equity owners for the purpose of aligning the interests of our officers with those of our stakeholders.

Our strategy since September 2009 has been to structure our compensation program so that we may seek out highly qualified and experienced individuals capable of contributing to the continued growth of our development stage company, both in terms of size and enterprise value, and an effective transition into the new obligations we will face as a SEC registrant. Accordingly, over the course of the past several months, we have undertaken various reporting company preparedness initiatives to ensure the competiveness of our executive compensation programs and further align the interests of our executive officers and other employees with the long-term objectives of our company. In particular, we engaged a compensation consultant to benchmark our officers' compensation to ensure that our programs are roughly in the median range of our peer group companies. This engagement is discussed in more detail below under " Implementing Our Objectives."

Implementing Our Objectives

Role of the Board of Directors, Compensation Committee and our Executive Officers

Executive compensation decisions are typically made on an annual basis by the Compensation Committee with input from Paul M. Rady, our Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer. Specifically, Messrs. Rady and Warren, based on information provided by the compensation consultant and their review of market data, provide recommendations to the Compensation Committee regarding the compensation levels for our existing executive officers (including themselves) and our executive compensation program as a whole. After considering these recommendations, the Compensation Committee typically adjusts base salary levels, determines the amounts of cash bonus awards and determines the amount and vesting of any equity grants for each of our executive officers. In making executive compensation decisions and recommendations, Messrs. Rady and Warren consider the executive officers' performance during the year and the company's performance during the year, but rely primarily on their business judgment and personal experience.

Table of Contents

While the Compensation Committee gives considerable weight to Messrs. Rady and Warren's recommendations on compensation matters, the Compensation Committee has the final decision-making authority on all executive compensation matters. No other executive officers have assumed a role in the evaluation, design or administration of our executive officer compensation program.

Role of External Advisors

In September 2009, our management engaged Cogent Compensation Partners, Inc. ("Cogent") to provide periodic executive compensation consulting services. Cogent does not currently provide any other services to our company. Management's objective when hiring Cogent was to assess our level of competitiveness for executive-level talent and receive recommendations for attracting, motivating and retaining key employees in light of our transition into the new obligations we will face as a SEC registrant. As part of its engagement, Cogent:

- Collected and reviewed all relevant company information, including our historical executive compensation data and our organizational structure, and conducted individual interviews with our executive officers and our largest institutional investors to gain insight into the vision, business strategy, culture and effectiveness of our current executive compensation program as well as expectations for the future;
- With the input of management, established a peer group of companies to use for executive compensation comparisons;
- Assessed our compensation program's position relative to the market for our top eight executive officers and our stated compensation philosophy; and
- Prepared a report of its analysis, findings and recommendations for our executive compensation program.

Cogent's report was presented to the Board of Directors as a whole in September 2009. The report was utilized by Messrs. Rady and Warren when making their recommendations to the Board of Directors for the fiscal 2010 compensation decisions.

Competitive Benchmarking

When formulating their compensation recommendations for the Compensation Committee, Messrs. Rady and Warren compare the pay practices for our executive officers against other companies to assist them in the review and comparison of base salary and incentive compensation for our executive officers. This practice recognizes that, while our compensation practices should be competitive in the marketplace, marketplace information is one of the many factors considered in assessing the reasonableness of our executive compensation program.

Prior to September 2009, Messrs. Rady and Warren made informal comparisons of our executive compensation program to the compensation paid to executives of publicly traded and other privately held companies similar in size and location to our company. In December 2008, Messrs. Rady and Warren used a survey from the Mountain States Employers Council as part of their informal competitive market analysis. Messrs. Rady and Warren did not review the data specific to any company participating in this survey and were not familiar with the identities of such companies. Rather, the aggregate data was merely used as a subjective frame of reference for similarly situated officers to help determine a potential range of compensation, which was then balanced against a variety of factors in making a final recommendation of each officer's compensation.

Beginning in September 2009, Messrs. Rady and Warren took a more formal approach and hired Cogent to assess the compensation levels of our top eight executive officers relative to the market. In addition, Messrs. Rady and Warren used statistical information from the 2009 Oil and Gas E&P

Table of Contents

Industry Compensation Survey prepared by Effective Compensation, Incorporated ("ECI") to supplement Cogent's peer group data. Messrs. Rady and Warren considered the results of the Cogent and ECI survey data when making their recommendations to the Board of Directors for the fiscal 2010 compensation decisions.

Cogent Survey Data. Cogent used the following parameters when constructing the peer group for its assessment: (1) resource-focused exploration and production companies that are publicly traded (without regard to size), (2) companies with a good performance track record, (3) companies with a strong management team with technical expertise and (4) companies with more than $1.0 billion in enterprise value. Using these parameters and collaborating with Messrs. Rady and Warren, Cogent developed a 19-company industry reference group (the "Cogent Peer Group"). The Cogent Peer Group included the following companies:

Berry Petroleum Company

Bill Barrett Corporation

Cabot Oil & Gas Corporation

Carrizo Oil & Gas, Inc.

Comstock Resources, Inc.

Concho Resources Inc.

Continental Resources, Inc.

Encore Acquisition Company

EXCO Resources, Inc.

Newfield Exploration Company

Petrohawk Energy Corporation

Quicksilver Resources, Inc.

Range Resources Corporation

Sandridge Energy, Inc.

Southwestern Energy Company

Ultra Petroleum Corp.

ECI Survey Data. An ECI survey was used because it is specific to the energy industry and derives its data from direct contributions from a large number of participating companies with which we believe we compete for talent. The survey was used to compare our executive compensation program against the following companies, which were selected by Messrs. Rady and Warren, and which have comparable revenues, market capitalization, capital expenditure budgets, business strategies, geographic and geologic focus and number of employees (the "ECI Peer Group"):

Berry Petroleum Company

Bill Barrett Corporation

Cimarex Energy Co.

Comstock Resources, Inc.

Concho Resources Inc.

Table of Contents

- Forest Oil Corporation
- Mariner Energy, Inc.
- Quicksilver Resources Inc.
- St. Mary Land & Exploration Company
- Whiting Petroleum Corporation

Due to the broad responsibilities of our executive officers and our status as a privately held company, comparing survey data to the job descriptions of our executive officers is sometimes difficult. However, as discussed above, our compensation objective is designed to be competitive with the peer companies listed above and, therefore, Messrs. Rady and Warren target compensation levels that are generally in the 50th percentile of the survey information reviewed when formulating their recommendations for the Compensation Committee. We believe that targeting this level of compensation helps us meet our overall total rewards strategy and executive compensation objectives outlined above.

Elements of Compensation

Compensation of our executive officers includes the following key components:

- Base salaries;
- Annual cash incentive payments;
- Transaction bonuses; and
- Long-term equity-based incentive awards.

Base Salaries

Base salaries are designed to provide a minimum, fixed level of cash compensation for services rendered during the year. Base salaries are generally reviewed annually, but are not automatically increased if the Compensation Committee believes that (1) our executives are currently compensated at proper levels in light of either our internal performance or external market factors, or (2) an increase or addition to other elements of compensation would be more appropriate in light of our stated objectives.

In addition to providing a base salary that is competitive with other independent oil and gas exploration and production companies, we also consider internal pay equity factors to appropriately align each of our Named Executive Officer's salary levels relative to the salary levels of our other officers so that it accurately reflects the officer's relative skills, responsibilities, experience and contributions to our company. To that end, annual salary adjustments are based on a subjective analysis of many individual factors, including:

- the responsibilities of the officer;
- the period over which the officer has performed these responsibilities;

- the scope, level of expertise and experience required for the officer's position;
- the strategic impact of the officer's position; and
- the potential future contribution and demonstrated individual performance of the officer.

In addition to individual factors listed above, our overall business performance and implementation of company objectives are taken into consideration. While these metrics generally provide context for making salary decisions, base salary decisions do not depend on attainment of specific goals or performance levels and no specific weighting is given to one factor over another.

Fiscal 2009 Decisions. After reviewing the Mountain States Employers Counsel survey data and considering the individual and business factors described above, Messrs. Rady and Warren recommended, and the Compensation Committee approved, increases in the base salaries of our executive officers in December 2008 as shown in the table below.

Fiscal 2010 Decisions. In October 2009, after comparing base salary levels to the Cogent Peer Group and ECI Peer Group (as described in more detail above under " Competitive Benchmarking") and considering the individual and business factors described above, Messrs. Rady and Warren recommended, and the Board of Directors approved, increases in the base salaries of our executive officers as shown in the table below. These increases, which were effective as of November 2009, were made as part of the overall shift in our compensation strategy as described in more detail above under " Compensation Philosophy and Objectives of Our Compensation Program." The adjusted base salary amounts were slightly below or at the median of the Cogent Peer Group and ECI Peer Group.

Executive Officer	**Base Salary Prior to December 2008**	**Base Salary as of December 2008**	**Percentage Increase**	**Base Salary as of November 2009**	**Percentage Increase**
	($)	**($)**	**(%)**	**($)**	**(%)**
Paul M. Rady	235,000	240,000	2	450,000	88
Glen C. Warren, Jr.	218,000	222,500	2	375,000	69
Kevin J. Kilstrom	195,000	200,000	3	280,000	40
Robert E. Mueller	195,000	200,000	3	260,000	30
Alvyn A. Schopp	180,000	185,000	3	275,000	49

Annual Cash Incentive Payments

Annual cash incentive payments, which we also refer to as cash bonuses, are a key part of each Named Executive Officer's annual compensation package. The Compensation Committee believes that discretionary cash bonuses are an appropriate way to further our goals of attracting, retaining, and rewarding highly qualified and experienced officers and avoiding an environment that might cause undue pressure to meet specific financial or individual performance goals. Typically in December of each year, the Compensation Committee determines whether to pay cash bonuses from a bonus pool amount to some or all of our employees, including our executive officers, and, if so, the amount of any such cash bonuses (which may range from 0% to 100% of an executive officer's base salary). The Compensation Committee's decisions are based on recommendations from Messrs. Rady and Warren. The factors considered when determining the amount of discretionary cash bonus awards, if any, are similar to those considered when setting and adjusting base salaries. No particular weight is assigned to any of these factors.

Fiscal 2009 Decisions. A discretionary cash bonus was awarded to each of our Named Executive Officers in November 2009. These awards were based upon the factors noted above. The awards to each Named Executive Officer are reflected below in the "Bonus" column of the Summary Compensation Table.

Transaction Bonuses

Under Antero's limited liability company agreement, a "Transaction Bonus Pool" is created upon a direct or indirect disposition of all or substantially all the assets or equity interests of one of our

Table of Contents

operating subsidiairies. That Transaction Bonus Pool is an amount equal to three percent (3%) of the profit generated with respect to the disposition of a particular operating subsidiary. Profit is defined pursuant to the terms of Antero's limited liability company agreement. The Transaction Bonus Pool is available to pay bonuses to individuals who are employees of one of our operating subsidiaries as of the date of the disposition (including, potentially, our Named Executive Officers), but the amount of any individual's transaction bonus and whether any particular individual receives a transaction bonus in connection with a disposition will be determined by the Compensation Committee at the time of any disposition of an operating subsidiary. Transaction bonus awards are intended to incentivize our employees to increase the value of our operating subsidiaries for the benefit of our unitholders by allowing them to share in the profits of any disposition of any such operating subsidiary. The amount of any transaction bonus awards made to any employee will be offset against future amounts that such employee would be entitled to receive in connection with future distributions by Antero as a result of the ownership by such employee of certain units in Antero and in Antero Resources Employee Holdings LLC (which are described below under " Long-Term Equity-Based Incentive Awards").

Long-Term Equity-Based Incentive Awards

Our long-term equity-based incentive program is designed to provide each of our employees with an incentive to focus on the long-term success of our company and to act as a long-term retention tool by aligning the interests of our employees with those of our stakeholders.

Historically, each of the operating subsidiaries sponsored a stock incentive plan from which restricted stock and options were granted to certain employees, including the Named Executive Officers. The Compensation Committee believed that stock options and restricted stock awards incentivized strong performance by our employees, including our executive officers, by providing the opportunity to receive additional compensation as a result of increases in the values of each of the operating subsidiaries. Decisions concerning the granting of stock options and restricted stock awards were made on the same basis, and utilizing the same criteria, as decisions concerning the other compensation elements set forth above. Exercise prices of options granted were pre-determined during the negotiation of our two key equity commitments that were secured in February 2003 and August 2007. This process resulted in the establishment of exercise prices that were sometimes less than the estimated fair market value of the stock underlying the option on the date of grant. Each operating subsidiary's stock options were subject to the following vesting provisions: (1) proportionate vesting to the extent that the officer remained continuously employed on each of the first four anniversaries of a specified vesting commencement date ("time vesting") and (2) proportionate vesting based on the level of preferred equity capital invested in the common stock of the operating subsidiary ("dollar vesting"). Restricted stock awards were also subject to both time vesting and dollar vesting requirements.

The stock incentive plans of each of the operating subsidiaries were terminated immediately prior to the closing of the November 2009 corporate reorganization. In anticipation of the plan terminations and contingent on the closing of the transactions contemplated by our November 2009 corporate reorganization, the boards of directors of each of the operating subsidiaries granted any authorized but unissued in-the-money stock options to certain employees, including certain Named Executive Officers, to ensure that the cash out payments (as described below) would not result in any employee receiving a disproportionately lower level of compensation than the Compensation Committee had anticipated based on the principles and processes outlined above. At the time of the termination of the stock incentive plans, no other equity awards had been granted in 2009. As a result of the stock plan terminations, all of the outstanding options were cancelled through either (1) a mandatory surrender and exercise termination process (as applicable to outstanding options, if any, granted prior to July 13, 2006) ("Non-409A Options") or (2) a discretionary termination and cash out process (as applicable to outstanding options granted on or after July 13, 2006 ("409A Options"), which had been designed to comply with Section 409A ("Section 409A") of the Internal Revenue Code of 1986, as amended (the

Table of Contents

"Code"). Specifically, with regard to any Non-409A Options, each executive was provided an opportunity to pay the exercise price under some or all of the agreements relating to such options in exchange for a right to receive the number of our Class A-1 units that the executive would have received in connection with the 2009 corporate reorganization if the executive had been the owner of record of the number of shares of common stock underlying the Non-409A Options. However, none of the executives elected to exercise any of their Non-409A Options and, therefore, these options were cancelled without consideration. In exchange for the cancellation of each executive officer's 409A Options that were (a) vested as a result of both time vesting and dollar vesting (as described above) and (b) considered to be "in-the-money" because the fair market value per share of the shares underlying the option was greater than the exercise price per share of such shares, the executive officer became entitled to receive a cash payment from the applicable operating subsidiary that had granted the officer such option equal to the difference between the fair market value per share and the exercise price per share, less applicable taxes. A portion of the cash out payments necessary to satisfy applicable FICA tax requirements was remitted on behalf of each executive officer in December 2009. However, due to the applicable rules imposed under Section 409A, each operating subsidiary will pay the remaining portion of its respective cash out payment, if any, due to each executive officer in November 2010 without interest. The executive officers will receive the remaining portion of any cash out payments to which they are entitled regardless of whether they remain employed by us. All of the other 409A Options granted to the executive officers that did not constitute vested in-the-money options as of the closing of the November 2009 reorganization were cancelled by the operating subsidiaries effective as of the closing of the November 2009 reorganization without any payment or consideration. Any outstanding restricted stock held by the Named Executive Officers prior to the November 2009 corporate reorganization was either repurchased by the operating subsidiaries at a purchase price equal to the officer's original cost or exchanged for units in Antero in accordance with the Contribution Agreement dated as of November 3, 2009, the stock incentive plans, and the applicable grant agreements. In connection with the termination of the stock incentive plans, each of our employees, including the executive officers, also received a payment equal to $1,000, less applicable taxes, in exchange for signing a release and waiver of all claims and entitlements pursuant to the cancelled options and restricted stock awards granted by the operating subsidiaries.

In connection with the November 2009 corporate reorganization, Antero Resources Employee Holdings LLC ("Holdings") was established to hold a portion of Antero units that were set aside at the time of the reorganization to be used for employee incentive compensation. We grant units in Holdings to our employees, including our Named Executive Officers, as a means of providing them with long-term equity incentive compensation in an affiliated entity that may directly profit from any success we achieve. This structure enables us to identify a fixed number of Antero units on which any distributions will flow through Holdings to our employees. We believe that providing equity compensation from Holdings allows us to retain the ability to incentivize our executives to focus on our long-term success.

In November 2009, we granted certain restricted Class A-2 and Class B-2 unit awards in Holdings to each of our Named Executive Officers. These units are intended to constitute "profits interests" in Holdings that will participate solely in any future profits of Holdings that result from any distributions on our units that are held by Holdings. The allocation of numbers and classes of units in Holdings that were granted to each Named Executive Officer was determined at levels that considered each executives contribution to the growth of the company. The units vest in equal amounts on each of the first four anniversaries of the applicable vesting commencement date set forth in the Named Executive Officer's restricted unit agreement. While the vesting commencement date varies among the awards, the vesting commencement dates applicable to the unit grants were established as of a date that precedes the date on which the units were granted (for example, the Class B-2 units granted to Mr. Rady in November 2009 commenced vesting on August 10, 2007) in order to take into account the Named Executive Officer's prior service to our company. Therefore, as described below under

" Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table," all or a portion of the units granted to each Named Executive Officer were vested on the grant date.

Other Benefits

Health and Welfare Benefits. Our Named Executive Officers are eligible to participate in all of our employee health and welfare benefit plans on the same basis as other employees (subject to applicable law) to meet their health and welfare needs. These plans include medical and dental insurance, as well as medical and dependent care flexible spending accounts. These benefits are provided in order to ensure that we are able to competitively attract and retain officers and other employees. This is a fixed component of compensation, and these benefits are provided on a non-discriminatory basis to all employees.

Retirement Benefits. We maintain an employee retirement savings plan whereby employees may save for retirement or future events on a tax-advantaged basis. We have made only one employer discretionary contribution, in 2004, to the 401(k) plan on behalf of our participating employees. Participation in the 401(k) plan is at the discretion of each individual employee, and our Named Executive Officers participate in the plan on the same basis as all other employees.

Perquisites and Other Personal Benefits. We believe that the total mix of compensation and benefits provided to our executive officers is currently competitive and, therefore, perquisites should not play a significant role in our executive officers' total compensation.

Employment, Severance or Change in Control Agreements

We do not currently maintain any employment, severance or change in control agreements with any of our Named Executive Officers.

As discussed below under " Potential Payments Upon a Termination or a Change in Control," the Named Executive Officers could be entitled to receive certain payments or accelerated vesting of any of their unit awards that remain unvested upon their termination of employment with us under certain circumstances or the occurrence of certain corporate events.

Other Matters

Equity Ownership Guidelines and Hedging Prohibition

We do not currently have ownership requirements or an equity retention policy for our Named Executive Officers. We do not have a policy that restricts our executive officers from limiting their economic exposure to our equity. We will continue to periodically review best practices and reevaluate our position with respect to equity ownership guidelines and hedging prohibitions.

Tax and Accounting Treatment of Executive Compensation Decisions

The Board of Directors has not yet adopted a policy with respect to the limitation under Section 162(m) of the Code, which generally limits our ability to deduct compensation in excess of $1,000,000 to a particular executive officer in any year.

Table of Contents

Summary Compensation

The following table summarizes, with respect to our Named Executive Officers, information relating to the compensation earned for services rendered in all capacities during the fiscal year ended December 31, 2009.

Summary Compensation Table for the Year Ended December 31, 2009

Name and Principal Position	Year	Salary ($)	Bonus ($)	Option Awards(1) ($)	All Other Compensation (2) ($)	Total ($)
Paul M. Rady *(Chairman of the Board of Directors and Chief Executive Officer)*	2009	$ 275,000	$ 225,000	$ 168,013	$ 293,467	$ 961,480
Glen C. Warren, Jr. *(Director, President and Chief Financial Officer and Secretary)*	2009	$ 247,917	$ 175,000	$ 111,120	$ 195,967	$ 730,004
Kevin J. Kilstrom *(Vice President Production)*	2009	$ 213,333	$ 140,000	$	$ 348,973	$ 702,306
Robert E. Mueller *(Vice President Geology)*	2009	$ 210,000	$ 110,000	$ 78,006	$ 229,406	$ 627,412
Alvyn A. Schopp *(Vice President Accounting & Administration and Treasurer)*	2009	$ 200,000	$ 140,000	$ 150,007	$ 96,700	$ 586,707

(1) Represents the aggregate grant date fair value of the options granted in fiscal 2009, cal