ANTERO RESOURCES Corp
Form 10-K
February 25, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
or
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File No. 001 36120

ANTERO RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

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

(303) 357 7310

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, Par Value $0.01 Per Share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10 K or any amendment to this Form 10 K.

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

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

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

The aggregate market value of the voting common stock held by non affiliates of the registrant as of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $3.6 billion.

The registrant had 262,073,239 shares of common stock outstanding as of February 19, 2015.

Documents incorporated by reference: Portions of the registrant's proxy statement for its annual meeting of stockholders to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end are incorporated by reference into Part III of this Annual Report on Form 10 K.

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CAUTIONARY STATEMENT REGARDING FORWARD LOOKING STATEMENTS

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

Forward looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, natural gas liquids ("NGLs"), and oil prices;
- timing and amount of future production of natural gas, NGLs, and oil;
- hedging strategy and results;
- ability to utilize or monetize our firm transportation commitments;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs, and oil;
- leasehold or business acquisitions;
- costs of developing our properties;
- the operations of Antero Midstream Partners LP;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, marketing and transportation risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs, and oil reserves and in projecting

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future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading “Item 1A. Risk Factors” in this Annual Report on Form 10 K.

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

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

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

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

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and gas industry:

"Basin." A large natural depression on the earth's surface in which sediments, generally brought by water, accumulate.

"Bbl." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, NGLs, or water.

"Bcf." One billion cubic feet of natural gas.

"Bcfe." One billion cubic feet of natural gas equivalent with one barrel of oil, condensate or NGLs converted to six thousand cubic feet of natural gas.

"Btu." British thermal unit.

"Completion." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"DD&A." Depreciation, depletion, and amortization.

"Delineation." The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

"Developed acreage." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"Development well." A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Dry hole." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Exploratory well." A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock which has distinct characteristics that differs from nearby rock.

"Gross acres or gross wells." The total acres or wells, as the case may be, in which a working interest is owned.

“Horizontal drilling.” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

“MBbl.” One thousand barrels of crude oil, condensate or NGLs.

“Mcf.” One thousand cubic feet of natural gas.

"MMBbl." One million barrels of crude oil, condensate or NGLs.

"MMBtu." One million British thermal units.

"MMcf." One million cubic feet of natural gas.

"MMcf/d" MMcf per day.

"MMcfe." One million cubic feet of natural gas equivalent with one barrel of oil, condensate or NGLs converted to six thousand cubic feet of natural gas.

"MMcfe/d." MMcfe per day.

"NGLs." Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

"NYMEX." The New York Mercantile Exchange.

"Net acres." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% working interest in 100 acres owns 50 net acres.

"Net well." The percentage ownership interest in a well that an owner has based on the working interest. An owner who has a 50% working interest has a 0.50 net well.

"Potential well locations." Total gross resource play locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Prospect." A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

"Proved developed reserves." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves." The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves ("PUD")." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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"PV 10." When used with respect to natural gas and oil reserves, PV 10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non property related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV 10 is not a financial measure calculated in accordance with generally accepted accounting principles ("GAAP") and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV 10 nor Standardized Measure represents an estimate of the fair market value of our natural gas and oil properties. We and others in the industry use PV 10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

"Recompletion." The process of re entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Spacing." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40 acre spacing, or distance between two horizontal well legs, and is often established by regulatory agencies.

"Standardized measure." Discounted future net cash flows estimated by applying year end prices to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"Undeveloped acreage." Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas, NGLs, and oil regardless of whether such acreage contains proved reserves.

"Unit." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Working interest." The right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"WTI." West Texas Intermediate light sweet crude oil.

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PART I

Items 1 and 2. Business and Properties

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2014, we held approximately 543,000 net acres of oil and gas properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. Our corporate headquarters are in Denver, Colorado.

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

	At December 31, 2014					Three months ended December 31, 2014
	Proved Reserves (Bcfe)(1)	PV-10 (in millions)(2)	Net proved developed wells(3)	Total net acres(4)	Gross potential drilling locations(5)	Average net daily production (MMcfe/d)
Appalachian Basin:						
Marcellus Shale	11,918	$ 9,920	367	395,000	3,191	1,074
Upper Devonian	8	$ 8	2	—	1,116	—
Deep Utica Shale rights	—	—	—	—	—	—
Utica Shale	757	$ 1,392	53	148,000	1,024	191
Total	12,683	$ 11,320	422	543,000	5,331	1,265

(1) Estimated proved reserve volumes and values were calculated assuming ethane rejection and using the unweighted twelve month average of the first day of the month reference prices for the period ended December 31, 2014, which were $4.07 per MMBtu for natural gas, $45.89 per Bbl for NGLs and $81.48 per Bbl for oil for the Appalachian Basin based on a $94.42 WTI reference price.

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

(3) Does not include certain shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions.

(4) Net acres allocable to the Upper Devonian and the deep Utica Shale rights are included in the net acres allocated to the Marcellus Shale, because these multi horizon shale formations are generally attributable to the same leases.

(5) See "Item 1A. Risk Factors" for risks and uncertainties related to developing our potential well locations.

Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas and NGLs resource plays to profitably grow our reserves and production, primarily on our existing multi year project inventory.

We have assembled a portfolio of long lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. From 2008 through December 31, 2014, our drilling operations in the Appalachian Basin have had a 100% success rate. We have approximately 5,331 potential horizontal well locations on our existing leasehold acreage, both proven and unproven.

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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 current development plans.

We operate in the following industry segments: (i) the exploration, development and production of natural gas, NGLs, and oil, (ii) gathering and compression, (iii) fresh water distribution, and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States. Financial information for our industry segment operations is located under "Note 13: Segment Information".

2014 Developments and Highlights

Energy Industry Environment

Recently, global energy commodity prices have declined precipitously as a result of several factors including increased worldwide supplies, a stronger U.S. dollar, relatively mild weather in the U.S., and strong competition among oil producing countries for market share. Specifically, prices for WTI have declined from approximately $106.00 per Bbl in June 2014 to less than $50.00 per Bbl in January 2015. Henry Hub natural gas has traded around $3.00 per MMBtu in January 2015 compared to prices a year ago in January 2014 of around $4.40 per MMBtu. In response to these market conditions and concerns about access to capital markets, U.S. exploration and development companies have significantly reduced capital spending plans. Our capital budget for 2015 is $1.8 billion (not including the capital budget of Antero Midstream Partners LP), a 41% reduction from our final 2014 capital budget. We plan to operate an average of 14 drilling rigs in 2015 down from 21 at December 31, 2014 and to complete 130 horizontal Marcellus and Utica wells in 2015, down from 177 in 2014. We believe that our 2015 capital budget will be fully funded through operating cash flow and available borrowing capacity under our revolving credit facility. We will continue to monitor commodity prices and may revise the capital budget if conditions warrant.

Initial Public Offering of Subsidiary

On November 10, 2014, our subsidiary, Antero Midstream Partners LP ("Antero Midstream"), completed its initial public offering ("IPO"). We contributed midstream gathering and compression assets to Antero Midstream as well as rights to develop additional midstream infrastructure to service our growing production. Additionally, Antero Midstream has an option to purchase our fresh water distribution systems at fair market value. A total of 46 million common units representing limited partner interests were sold in the IPO at a price to the public of $25.00 per common unit. After subtracting underwriting discounts and offering costs, net proceeds received by Antero Midstream were approximately $1.1 billion. Antero Midstream used approximately $843 million of the net proceeds to repay indebtedness assumed from us and to reimburse us for certain capital expenditures incurred. Antero Midstream retained $250 million of the net proceeds for general partnership purposes. After completion of the IPO, we own approximately 69.7% of the outstanding limited partner interests in Antero Midstream and the public owns the remaining 30.3% of the limited partner interests in Antero Midstream.

Reserves, Production, and Financial Results

As of December 31, 2014, our estimated proved reserves were 12.7 Tcfe, consisting of 10.5 Tcf of natural gas, 330 MMBbl of NGLs and 28 MMBbl of oil. As of December 31, 2014, 83% of our estimated proved reserves by volume were natural gas, 16% were NGLs, and 1% was oil. Proved developed reserves were 3.8 Tcfe, or 30% of total proved reserves.

For the year ended December 31, 2014, our production totaled 368 Bcfe, or 1,007 MMcfe per day. The 2014 production levels represent a 93% increase over 2013 levels. The average price received for 2014 production before the effects of realized hedge gains was $4.73 per Mcfe compared to $4.31 in 2013. The 10% increase was primarily attributable to the increased proportion of NGLs and oil production to total production in 2014 compared to the prior year. Average prices after the effects of cash settled commodity hedges were $5.10 per Mcfe for 2014 compared to $5.17 per Mcfe for 2013.

For the year ended December 31, 2014, we generated cash flow from operations of $998 million, net income of $674 million, and Adjusted EBITDAX of $1.2 billion. Net income in 2014 included (i) unrealized hedge gains of $732 million (ii) a noncash charge of $112 million for equity-based compensation, (iii) a noncash tax expense of $446 million, (iv) a charge of $20 million for redemption premiums and the write off of unamortized deferred financing charges and premium associated with the retirement of $260 million of our 7.25% senior notes due 2019, and (v) income from discontinued operations of $2 million. See “Item 6. Selected Financial Data” for a definition of Adjusted EBITDAX (a non GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

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2014 Capital Spending and 2015 Capital Budget

For the year ended December 31, 2014, our total capital expenditures were approximately $4.1 billion, including drilling and completion costs of $2.5 billion, gathering and compression project costs of $558 million, fresh water distribution project costs of $197 million, $841 million of leasehold costs (including $415 million of acquisitions and $426 million on land), and other capital expenditures of $13 million. Our capital budget for 2015 is $1.8 billion and includes: $1.6 billion for drilling and completion; $50 million for fresh water distribution infrastructure; and $150 million for core leasehold acreage acquisitions. We do not budget for producing property acquisitions. All of the $1.6 billion allocated for drilling and completion is allocated to our operated drilling in liquids-rich gas areas. Approximately 60% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 40% is allocated to the Utica Shale. During 2015, we plan to operate an average of nine drilling rigs in the Marcellus Shale and five drilling rigs in the Utica Shale. Additionally, the capital budget for Antero Midstream for 2015 is a range of $425 million to $450 million. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, commodity prices, and liquidity.

Hedge Position

At December 31, 2014, we had entered into hedging contracts for January 1, 2015 through December 31, 2020 for 1.758 Tcf of our projected natural gas production at a weighted average index price of $4.41 per MMBtu, 1.1 million Bbls of oil at a weighted average price of $64.58 per Bbl, and 352.6 million gallons of propane at a weighted average price of $0.61 per gallon. These hedging contracts include contracts for the year ending December 31, 2015 of approximately 423.4 Bcf of natural gas at a weighted average index price of $4.34 per MMBtu, 1.1 million Bbls of oil at a weighted average price of $64.58 per Bbl, and 352.6 million gallons of propane at a weighted average price of $0.61 per gallon. We believe this hedge position provides protection to cash flows supporting our future operations and capital spending plans for 2015 through 2020.

Credit Facilities

The current borrowing base under our revolving credit facility is $4.0 billion and lender commitments are $4.0 billion. The borrowing base under our revolving credit facility is redetermined semi annually and is based on the estimated future cash flows from our proved reserves and our hedge positions. The next redetermination is scheduled to occur in October 2015. Our revolving credit facility provides for a maximum availability of $4.0 billion. At December 31, 2014, we had $1.73 billion of borrowings and $387 million of letters of credit outstanding under the revolving credit facility. Our revolving credit facility matures in May 2019. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Senior Secured Revolving Credit Facility" for a description of our revolving credit facility.

On November 10, 2014, in connection with the closing of the Antero Midstream IPO, Antero Midstream entered into a revolving credit facility agreement that provides for lender commitments of $1.0 billion. The facility will mature on November 10, 2019. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Midstream Credit Facility" for a description of this revolving credit facility.

Issuance of $1.1 Billion 5.125% Senior Notes Due 2022

On May 6, 2014, we issued $600 million of 5.125% senior notes due 2022 (the "2022 notes") at par. Net proceeds from the offering of $592 million were used to retire the remaining $260 million principal amount of our 7.25% notes due 2019 and for general corporate purposes, including paying down amounts outstanding under our revolving credit facility and funding our drilling and development program. We incurred a loss on early extinguishment of debt of $20 million on the retirement of the 7.25% notes. On September 18, 2014, we issued an additional $500 million of the 2022 notes at 100.5% of par. The net proceeds from the additional issuance of 2022 notes were used to pay down amounts outstanding under our revolving credit facility.

As of December 31, 2014, we had three series of senior notes outstanding totaling $2.6 billion in aggregate principal amount. The notes have maturity dates ranging from December 1, 2020 to December 1, 2022, and interest rates ranging from 5.125% to 6.00%.

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Our Properties and Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared in accordance with the rules and regulations of the SEC.

Reserves Presentation

The following table summarizes our estimated proved reserves and related standardized measure and PV 10 at December 31, 2012, 2013, and 2014. Our estimated proved reserves are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent engineers, DeGolyer and MacNaughton ("D&M"). We refer to D&M as our independent engineers. A copy of the summary report of D&M with respect to our reserves at December 31, 2014 is filed as Exhibit 99.1 to this Annual Report on Form 10 K. The information in the following table does not give any effect to or reflect our commodity hedges. Reserves at December 31, 2012 were prepared assuming ethane recovery from our production process, while reserves at December 31, 2013 and 2014 were prepared assuming ethane rejection. When ethane is rejected at the processing plant, it is left in the gas stream and sold with the methane gas.

	At December 31,		
	2012	2013	2014
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	828	1,818	3,285
NGLs (MMBbl)	36	33	80
Oil (MMBbl)	1	2	6
Total equivalent proved developed reserves (Bcfe)	1,047	2,022	3,803
Proved undevoped reserves:			
Natural gas (Bcf)	2,866	4,936	7,250
NGLs (MMBbl)	167	105	250
Oil (MMBbl)	2	8	22
Total equivalent proved undeveloped reserves (Bcfe)	3,882	5,610	8,880
Total estimated proved reserves (Bcfe)	4,929	7,632	12,683
Proved developed producing (Bcfe)	935	1,771	3,508
Proved developed non-producing (Bcfe)	112	251	295
Percent developed	21 %	27 %	30 %
PV-10 (in millions)(1)	$ 1,923	$ 5,998	$ 11,320
Standardized measure (in millions)(1)	$ 1,601	$ 4,510	$ 7,635

(1) Pre-tax PV 10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. Pre-tax PV 10 is a non GAAP financial measure. We believe that the presentation of pre-tax 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, pre-tax PV 10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, pre-tax 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 pre-tax PV 10 amount is the discounted amount of estimated future income taxes. For more information about the calculation of standardized measure, see footnote 18 to our consolidated financial statements included in Item 8 of this Annual Report on Form 10 K.

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The following sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV 10), the present value of those net cash flows after income tax (standardized measure) and the prices used in projecting future net cash flows at December 31, 2012, 2013, and 2014:

	At December 31,		
(In millions, except per Mcf data)	2012(1)	2013(2)	2014(3)
Future net cash flows	$ 7,221	$ 18,797	$ 33,698
Present value of future net cash flows:			
Before income tax (PV-10)	$ 1,923	$ 5,998	$ 11,320
Income taxes	$ (322)	$ (1,488)	$ (3,685)
After income tax (Standardization measure)	$ 1,601	$ 4,510	$ 7,635

(1) 12 month average prices used at December 31, 2012 were $2.78 per MMBtu for natural gas, $19.61 per Bbl for NGLs, and $85.05 per Bbl for oil for the Appalachian Basin based on a $95.05 WTI reference price.
(2) 12 month average prices used at December 31, 2013 were $3.65 per MMBtu for natural gas, $47.13 per Bbl for NGLs, and $87.00 per Bbl for oil for the Appalachian Basin based on a $97.17 WTI reference price.
(3) 12 month average prices used at December 31, 2014 were $4.07 per MMBtu for natural gas, $45.89 per Bbl for NGLs, and $81.48 per Bbl for oil for the Appalachian Basin based on a $94.42 WTI reference price.

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Prices for 2012, 2013, and 2014 were based on 12 month unweighted average of the first day of the month pricing, without escalation. Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Changes in Proved Reserves During 2014

The following table summarizes the changes in our estimated proved reserves during 2014 (in Bcfe):

Proved reserves, December 31, 2013	7,632
Extensions, discoveries, and other additions	6,444
Purchase of reserves	29
Performance revisions	361
Revisions due to 5-year development rule	(1,417)
Price revisions	2
Production	(368)
Proved reserves, December 31, 2014	12,683

Extensions, discoveries, and other additions during 2014 of 6,444 Bcfe were added through delineation and developmental drilling in the Marcellus and Utica Shales. Purchases of 29 Bcfe relate to five horizontal producing wells acquired as part of our leasehold acquisition efforts. Performance revisions of 361 Bcfe relate to improved well performance from shorter stage length completions. Downward revisions of 1,417 Bcfe were due to the reclassification of 191 dry gas locations to the probable category because they are no longer expected to be drilled within five years of initial booking. Upward price revisions of 2 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the reference prices for NGLs and oil. Our estimated proved reserves as of December 31, 2014 totaled approximately 12.7 Tcfe and increased by 66% over the prior year.

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Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated proved undeveloped reserves during 2014 (in Bcfe):

Proved undeveloped reserves, December 31, 2013	5,610
Extension, discoveries, and other additions	5,570
Reclassifications to proved developed reserves	(1,112)
Performance revisions	228
Revisions due to 5-year development rule	(1,417)
Price revisions	1
Proved undeveloped reserves, December 31, 2014	8,880

Extensions, discoveries, and other additions during 2014 of 5,570 Bcfe of proved undeveloped reserves were added through delineation and developmental drilling in the Marcellus and Utica Shales. Development drilling resulted in the reclassification of 1,112 Bcfe to proved developed reserves. Performance revisions of 228 Bcfe relate to improved well performance from shorter stage length completions. Downward revisions of 1,417 Bcfe due were due to the reclassification of 191 dry gas wells to the probable category because they are no longer expected to be drilled within five years of initial booking, as our drilling plans are more focused on our liquids-rich acreage. Upward price revisions of 1 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the reference prices for NGLs and oil. Proved undeveloped reserves include reserves that are expected to be drilled and developed within five years; wells that are not drilled within five years from booking are reclassified from proved reserves to probable reserves.

During the year ended December 31, 2014, we converted approximately 1,112 Bcfe of proved undeveloped reserves to proved developed reserves at a total capital cost of approximately $991 million. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2014 are approximately $8.2 billion over the next five years, which we expect to finance through cash flow from operations, borrowings under our revolving credit facility, and other sources of capital financing. Our drilling programs to date have focused on proving our undeveloped leasehold acreage through delineation drilling. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also continue drilling our proved undeveloped reserves. All of our proved undeveloped reserves are expected to be developed over the next five years. See "Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2012, 2013, and 2014 included in this Annual Report on Form 10 K were prepared by our internal reserve engineers in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserve auditing process. Periodically, our technical team meets with the independent reserve engineers to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Our internally prepared reserve estimates and related reports are reviewed and approved by our Vice President of Reserves, Planning & Midstream, Ward D. McNeilly, and our Vice President of Production, Kevin J. Kilstrom. Mr. McNeilly has been with the Company since October 2010. Mr. McNeilly has 35 years of experience in oil and gas operations, reservoir management, and strategic planning. From 2007 to October 2010 Mr. McNeilly was the Operations Manager for BHP Billiton's Gulf of Mexico operations. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. From 1979 through 1996 Mr. McNeilly served in various domestic and international operations and reservoir and asset management positions with Amoco. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

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

Proved reserves are reserves 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 under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, micro seismic data and well test data. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us. Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

Methodology Used to Apply Reserve Definitions

In the Marcellus Shale, our estimated reserves are based on information from our large, operated proved developed producing reserve base, as well as information from other operators in the area, which can be used to confirm or supplement our internal estimates. Typically, proved undeveloped properties are booked based on applying the estimated lateral length to the average Bcf per 1,000 feet from our proved developed producing wells.

We may attribute up to 11 proved undeveloped locations based on one proved developed producing well where analysis of geologic and engineering data can be estimated with reasonable certainty to be commercially recoverable. However, the ratio of proved undeveloped locations generated will be lower when multiple proved developed wells are drilled on a single pad. In addition, we have applied the concept of a Highly Developed Area, or HDA, to certain areas of our Marcellus Shale acreage whereby undeveloped properties are booked as proved reserves so long as well count is sufficient for statistical analysis and certain land, geologic, engineering and commercial criteria are met.

Although our operating history in the Utica Shale is more limited than our Marcellus Shale operations, we expect to be able to apply a similar methodology once the well count is sufficient for statistical analysis. The primary differences between the two areas are that (i) we have not established an HDA in the Utica Shale and (ii) each proved developed producing well in the Utica Shale only generates four direct offset well locations in the Utica Shale due to less relative maturity.

Identification of Potential Well Locations

Our identified potential well locations include locations to which proved, probable or possible reserves were attributable based on SEC pricing as of December 31, 2014. We prepare internal estimates of probable and possible reserves but have not included disclosure of such reserves in this report.

Production, Revenues, and Price History

Because natural gas, NGLs, and oil are commodities, the price that we receive for our production is largely a function of market supply and demand. While demand for natural gas in the United States has increased materially since 2000, natural gas and NGLs supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have

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been used to find and recover large amounts of oil and gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. The significant commodity price declines in late 2014 and early 2015 are the most recent example of such volatility. 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 reserves that may be economically produced and our ability to access capital markets. See "Item 1A. Risk Factors—Natural gas, NGLs, and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

The following table sets forth information regarding our production, revenues and realized prices, and production costs from continuing operations in the Appalachian Basin for the years ended December 31, 2012, 2013 and 2014. For additional information on price calculations, see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Continuing Operations Data—Appalachian Basin

	Year ended December 31,		
	2012	2013	2014
Production data:			
Natural gas (Bcf)	87	177	317
NGLs (MBbl)	71	2,123	7,102
Oil (MBbl)	19	226	1,311
Combined (Bcfe)	87	191	368
Daily combined production (MMcfe/d)	239	522	1,007
Average prices before effects of hedges:			
Natural gas (per Mcf)	$ 2.99	$ 3.90	$ 4.10
NGLs (per Bbl)	$ 52.07	$ 52.61	$ 46.23
Oil (per Bbl)	$ 80.34	$ 91.27	$ 81.65
Combined average sales prices before effects of cash settled derivatives (per Mcfe)(1)	$ 3.03	$ 4.31	$ 4.73
Combined average sales prices after effects of cash settled derivatives (per Mcfe)(1)	$ 5.08	$ 5.17	$ 5.10
Average Costs (per Mcfe):			
Lease operating	$ 0.07	$ 0.05	$ 0.08
Gathering, compression, processing, and transportation	$ 1.04	$ 1.15	$ 1.26
Production and ad valorem taxes	$ 0.23	$ 0.26	$ 0.24
Depletion, depreciation, amortization, and accretion			