SOUTHWESTERN ENERGY CO
Form 10-K
February 26, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2014
Commission file number 1-08246

Southwestern Energy Company
(Exact name of registrant as specified in its charter)

Delaware	71-0205415
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

10000 Energy Drive,

Spring, Texas	77389
(Address of principal executive offices)	(Zip Code)

(832) 796-1000
(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	New York Stock Exchange
Depositary Shares, each representing a 1/20th ownership interest in a share of 6.25% Series B Mandatory Convertible Preferred Stock	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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12

months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark 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 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 stock held by non-affiliates of the registrant was $15,884,399,197 based on the New York Stock Exchange Composite Transactions closing price on June 30, 2014 of $45.49. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 24, 2015, the number of outstanding shares of the registrant s Common Stock, par value $0.01, was 384,480,028.

Document Incorporated by Reference

Portions of the registrant s definitive proxy statement to be filed with respect to the annual meeting of stockholders to be held on or about May 19, 2015 are incorporated by reference into Part III of this Form 10-K.

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SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2014

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This Annual Report on Form 10-K includes certain statements that may be deemed to be forward-looking within the meaning of Section 27A of the Securities Act of 1933, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to Risk Factors in Item 1A of Part I and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, the Compensation, and the Nominating and Governance Committees of our Board of Directors are available on our website, and are available in print free of charge to any stockholder upon request. Information on our website is not incorporated into this report.

We file periodic reports and proxy statements with the SEC. The public may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC s website is www.sec.gov.

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ITEM 1. BUSINESS

Southwestern Energy Company (including its subsidiaries, collectively, we , Southwestern or the Company) is an independent energy company engaged in natural gas and oil exploration, development and production (E&P). We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We conduct substantially all of our business through subsidiaries.

Exploration and Production - Our primary business is the exploration for and production of natural gas and oil, with our current operations principally focused within the United States on development of two unconventional natural gas reservoirs located in Arkansas and Pennsylvania. Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale, and our operations in northeast Pennsylvania are focused on the unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as Northeast Appalachia). Recently, we acquired a significant stake in properties located in West Virginia and southwest Pennsylvania, which we also intend to develop. These operations in West Virginia also focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as Southwest Appalachia). Collectively, our properties located in West Virginia and Pennsylvania are herein referred to as the Appalachian Basin. To a lesser extent, we have exploration and production activities ongoing in Colorado, Louisiana, Texas and in the Arkoma Basin in Arkansas and Oklahoma. We also actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as New Ventures, and through acquisitions. We also operate drilling rigs in Arkansas and Pennsylvania, as well as in other operating areas, and provide oilfield products and services, principally serving our exploration and production operations.

Midstream Services - We engage in natural gas gathering activities in Arkansas, Texas, Louisiana, Pennsylvania, and West Virginia. These activities primarily support our E&P operations and generate revenue from fees associated with the gathering of natural gas. Our marketing activities capture downstream opportunities that arise through the marketing and transportation of the natural gas, oil and natural gas liquids (NGLs) produced in our E&P operations.

The vast majority of our operating income and earnings before interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties or (gain) loss on derivatives, excluding derivatives, settled (Adjusted EBITDA), are derived from our E&P business. In 2014, 74% of our operating income and 82% of our Adjusted EBITDA were generated from our E&P business, compared to 73% of our operating income and 81% of our Adjusted EBITDA in 2013 and, 65% of our operating income, absent our $1,940 million, or $1,192 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties, and 79% of our Adjusted EBITDA in 2012. The remainder of our consolidated operating income and Adjusted EBITDA in each of these years was generated from Midstream Services. Adjusted EBITDA is a non-GAAP measure. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Reconciliation of Non-GAAP Measures in Item 7 of Part II of this Annual Report for a table that reconciles Adjusted EBITDA to net income (loss).

In December 2014, our principal executive offices moved to 10000 Energy Drive, Spring, Texas 77389. Our telephone number is (832) 796-4700. Our website is www.swn.com. The information included on our website is not part of, or incorporated by reference into, this Annual Report.

Our Business Strategy

Since 1999, our management has been guided by our formula, which represents the essence of our corporate philosophy and how we operate our business:

Our formula, which stands for The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets will create Value+, also guides our business strategy. We are focused on providing long-term growth in the net asset value of our business. In our E&P business, we prepare an economic analysis for each investment opportunity based upon the expected net present value added for each dollar to be invested, which we refer to as Present Value Index, or PVI. The PVI for each project is determined using a 10% discount rate. We target creating an average of at least $1.30 of pre-tax PVI for each dollar we invest in our E&P projects. Our actual PVI results are utilized to help determine the allocation of our future capital investments. The key elements of our business strategy are:

- Exploit and Develop Our Positions in the Fayetteville Shale and the Appalachian Basin. A key focus of the Company is to maximize the value of our significant acreage position in the Fayetteville Shale, which has provided significant production and reserve growth since we began drilling in 2004. As of December 31, 2014, we held approximately 888,161 net acres in the Fayetteville Shale, accounting for approximately 47% of our total proved natural gas and oil reserves and approximately 64% of our total natural gas and oil production during 2014. Additionally, we are actively drilling on portions of our 266,073 net acres in Northeast Appalachia and believe our production and reserves from the Marcellus Shale will grow substantially over the next few years. Our Northeast Appalachia acreage accounted for approximately 30% of our total proved natural gas and oil reserves and 33% of our total natural gas and oil production during 2014. We also closed a transaction for approximately 413,000 net acres, the Chesapeake Property Acquisition, in West Virginia and southwest Pennsylvania in December 2014 where we plan to target the Marcellus, Upper Devonian and Utica Shales, with an additional approximate 30,000 net acres which closed January 2015, the Statoil Property Acquisition. Additionally in January 2015, we closed a transaction for approximately 46,700 net acres in northeast Pennsylvania from WPX Energy, Inc. (WPX). We refer to the transaction with WPX as the WPX Property Acquisition. As of December 31, 2014, the reserves from the Chesapeake Property Acquisition accounted for approximately 22% of our total proved natural gas and oil reserves. We intend to further develop our acreage positions in the Fayetteville Shale and the Appalachian Basin and to improve our well results through the use of advanced technologies and detailed technical analysis of our properties. We refer to the Chesapeake, Statoil and WPX Property Acquisitions collectively as the Acquisitions.

- Grow through New Exploration and Development Activities Focusing on Emerging Unconventional Plays. We actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential. Our New Ventures prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria, and can be located both inside and outside of the United States. In addition to having E&P employees specifically focused on New Ventures activities, we also have a robust staff of employees focused on strategic business development activities. As of December 31, 2014, we held 4,170,687 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres are located in New Brunswick, Canada. During 2014, we purchased approximately 380,000 net acres in northwest Colorado principally in the Niobrara formation and are commencing exploration and development on these properties.
- Maximize Efficiency through Vertical Integration and Economies of Scale. In our key operating areas, the concentration of our properties allows us to achieve economies of scale that result in lower costs. We seek to serve as the operator of the wells in which we have a significant interest. As the operator, we are better positioned to control the drilling, completing and producing of wells and the marketing of production to minimize costs and maximize both production volumes and realized price. In the Fayetteville Shale and the Appalachian Basin, we have achieved significant cost savings through our vertical integration. Our vertical integration includes ownership of a sand mine in the Fayetteville Shale, that is a source of proppant for our well completions, and through our operation of other associated oilfield services, including a fleet of drilling rigs and two pressure pumping equipment spreads used for well completions.
- Enhance the Value of Our Midstream Operations. We have continued to design and improve our gas gathering infrastructure to better manage the physical movement of our production. As of December 31, 2014, we have invested approximately $1,184 million in the 2,017 mile gas gathering system built for our Fayetteville Shale asset, which was gathering approximately 2.4 Bcf per day at year-end, and have invested approximately $247 million in 146 miles of gas gathering lines in Pennsylvania, Louisiana and East Texas. Our gathering system in the Fayetteville Shale has developed into a strategic asset that supports our E&P operations.

Significant Accomplishments in 2014

Production and Reserve Growth. In 2014, our production was 768 Bcfe, or approximately 2.1 Bcfe per day, an increase of 17% from 2013 levels. This increase was driven primarily by production growth of 69% from our Northeast Appalachia division. Additionally, in 2014 our total proved reserves increased to the highest level in our company s history, growing by 54% to approximately 10.7 Tcfe.

Low Cost Structure. Our cost structure continues to be one of the lowest in the industry, with an all-in cash operating cost of $1.32 per Mcfe in 2014, compared to $1.25 per Mcfe in 2013. All-in cash operating cost per Mcfe is defined as the per Mcfe sum of our E&P segment s lease operating expenses, taxes (other than income taxes), general and administrative expenses, and net interest expense. We have included information concerning this ratio as it measures the cost efficiency of a company s oil and gas producing operations and is a measure commonly used in our industry.

Northeast Appalachia Achieves Significant Growth. Our Northeast Appalachia division drove our overall production growth in 2014, with gross operated production surpassing 1.0 Bcfe per day at year-end 2014 compared to 700 MMcf per day at year-end 2013. Production increased to 254 Bcf in 2014, compared to 151 Bcf in 2013, while total proved reserves increased to approximately 3.2 Tcf, compared to 2.0 Tcf in 2013.

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Fayetteville Shale Continues to Deliver. In 2014, our Fayetteville Shale division again had one of its best years ever. In its tenth year of development, the division achieved 24 of its best 30 wells based on average initial production rate as it applies the learnings obtained from its focus on innovation. Total proved reserves for the Fayetteville Shale increased in 2014 to approximately 5.1 Tcf, from 4.8 Tcf in 2013, and 2014 production increased to 494 Bcf, up from 486 Bcf in 2013.

Financial Flexibility. We ended 2014 with a capital structure that consisted of 60% debt and 40% equity and had approximately $1.7 billion of borrowing capacity available under our principal credit facility. In January 2015, we reduced our debt by approximately $2.3 billion through an equity offering. Had this equity offering occurred in 2014, our capital structure would have consisted of 40% debt and 60% equity. At December 31, 2014, our debt was rated as investment grade by three of the major rating agencies: BBB with a stable outlook by Standard and Poor s (S&P), BBB- with a stable outlook by Fitch Ratings (Fitch) and Baa3 with a stable outlook by Moody s Investors Service (Moody s). In January 2015, Standard and Poor s (S&P) downgraded us to BBB- with a stable outlook. We are committed to maintaining financial flexibility as it moves forward with the integration and development of the recently acquired assets in the Appalachian Basin.

Recent Developments

2015 Planned Capital Investments and Production Guidance. Excluding the capital associated with the closing of the WPX and Statoil Property Acquisitions, our planned capital investment program for 2015 is approximately $2.0 billion, which includes approximately $1.9 billion for our E&P segment, $85 million for our Midstream Services segment and $40 million for E&P services and corporate. The planned capital program for 2015 is flexible, and we will reevaluate our proposed investments as needed to take into account prevailing market conditions. Based on our capital program, we are targeting 2015 natural gas and oil production of approximately 940 to 955 Bcfe, an increase of approximately 23% over our 2014 production, using midpoints.

Equity Offering. In January 2015, we completed concurrent underwritten public offerings of 30,000,000 shares of our common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). Net proceeds from the offerings totaled approximately $2.3 billion after underwriting discount and offering expenses. The common stock offering was priced at $23.00 per share. Net proceeds, after underwriting discount and expenses, from the common stock offering were approximately $669 million. Net proceeds, after underwriting discount and expenses, from the depositary share offering were approximately $1.7 billion. Each depositary share represents a 1/20th interest in a share of our 6.25% Series B Mandatory Convertible Preferred Stock, with a liquidation preference of $1,000 per share (equivalent to a $50 liquidation preference per depositary share). The proceeds from the offerings were used to partially repay borrowings under our $4.5 billion 364-day bridge term loan facility incurred in connection with the Chesapeake Property Acquisition.

Debt Offering. In January 2015, we completed a public offering of $350 million aggregate principal amount of our 3.300% senior notes due 2018 (the 2018 Notes), $850 million aggregate principal amount of our 4.050% senior notes due 2020 (the 2020 Notes) and $1 billion aggregate principal amount of our 4.950% senior notes due 2025 (the 2025 Notes and together with the 2018 Notes and the 2020 Notes, the Notes), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The proceeds from the offering were used to repay all principal and interest remaining outstanding under our $4.5 billion 364-day bridge term loan facility incurred in connection with the Chesapeake Property Acquisition and were used to repay a portion of amounts outstanding under our revolving credit facility.

Exploration and Production

Overview

Operations in our E&P segment are primarily in the Fayetteville Shale and Appalachian Basin assets. We also intend to conduct additional exploration and production activities in the Sand Wash Basin and other basins targeting various formations as part of our New Ventures projects. We continue to actively seek to acquire and develop both conventional and unconventional natural gas and oil resource plays with significant exploration and exploitation potential.

Our E&P segment recorded operating income of $1,013 million in 2014, operating income of $879 million in 2013, and an operating loss of $1,396 million in 2012 as a result of a $1,940 million, or $1,192 million net of taxes, non-cash ceiling test impairment of our United States natural gas and oil properties. Operating income for 2014 increased $134 million compared to 2013 as a result of an increase in revenue of $403 million from higher natural gas production volumes, an increase in revenue of $55 million from increased prices realized from the sale of our natural gas production, offset by an increase in operating costs and expenses of $324 million associated with the expansion of our operations and higher activity levels in the Fayetteville Shale and Northeast Appalachia. Operating income for 2013 increased $335 million

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compared to 2012 (excluding the $1,940 million non-cash ceiling test impairment recorded in 2012) as a result of an increase in revenue of $316 million from higher natural gas production volumes, an increase in revenue of $118 million from increased prices realized from the sale of our natural gas production and an increase in revenues of $6 million from higher oil volumes, offset by an increase in operating costs and expenses of $106 million associated with the expansion of our operations and higher activity levels in the Fayetteville Shale and Northeast Appalachia. Adjusted EBITDA from our E&P segment was $1.9 billion in 2014, compared to $1.6 billion in 2013 and $1.3 billion in 2012. Our Adjusted EBITDA increased in 2014 and 2013 as higher realized gas prices and production volumes more than offset increased total operating costs and expenses due to increased activity levels. Adjusted EBITDA is a non-GAAP measure. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Reconciliation of Non-GAAP Measures in Item 7 of Part II of this Annual Report for a table that reconciles Adjusted EBITDA to net income (loss).

Oilfield Services Vertical Integration

We seek to provide oilfield services that are strategic and economically beneficial for our E&P operations. This vertical integration lowers our net well costs, allows us to operate safely and efficiently and mitigates certain operational environmental risks. Among others, these services include drilling, hydraulic fracturing and the mining of proppant used for our well completions.

Sand Mine

Since 2009, we have owned and operated a sand mine to provide a reliable supply of proppant primarily used for the completion of our wells that we operate in the Fayetteville Shale. As of December 31, 2014, our sand mine is comprised of 570 acres and produces 30/70 and 100 mesh sized sand. In 2014, we provided sand for the completion of 453 wells operated by us in the Fayetteville Shale and were able to reduce our well completion costs on average by 9% per well for the wells for which we provided sand.

Hydraulic Fracturing

We provide pressure pumping services for a portion of our operated wells. As of December 31, 2014, we operated 2 leased pressure pumping spreads with a total capacity of approximately 72,000 horsepower to conduct a variety of completion services designed to stimulate natural gas production. In 2014, we provided pressure pumping services for 224 wells that we operated in the Fayetteville Shale and were able to reduce our well completion costs on average by 12% per well for the wells we completed.

Drilling Services

We conduct drilling operations for a portion of our operated wells. As of December 31, 2014, we operated 9 re-entry rigs and 2 spudder rigs which were operating in Arkansas, Pennsylvania and Louisiana. In 2014, we provided drilling services for 426 and 43 wells that we operate in the Fayetteville Shale and Northeast Appalachia, respectively, and were able to reduce our drilling costs on average by 4% and 1% per well for the wells we drilled in the Fayetteville Shale and Northeast Appalachia, respectively.

Our Proved Reserves

Our estimated proved natural gas and oil reserves were 10,747 Bcfe at year-end 2014, compared to 6,976 Bcfe at year-end 2013 and 4,018 Bcfe at year-end 2012. The significant increase in our reserves in 2014 was primarily due to the acquisition of approximately 413,000 net acres in Southwest Appalachia, our successful development drilling programs in the Fayetteville Shale and Northeast Appalachia and upward performance revisions in Northeast

Appalachia. Because our proved reserves are primarily natural gas, our reserve estimates and the after-tax PV-10 measure, or standardized measure of discounted future net cash flows relating to proved natural gas and oil reserve quantities, are highly dependent upon the natural gas price used in our reserve and after-tax PV-10 calculations. In order to value our estimated proved natural gas, NGL and oil reserves as of December 31, 2014, we utilized average prices from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.35 per MMBtu for natural gas, West Texas Intermediate oil of $91.48 per barrel for oil and $23.79 per barrel for NGLs compared to $3.67 per MMBtu for natural gas, $93.42 per barrel for oil, and $43.45 per barrel for NGLs at December 31, 2013 and $2.76 per MMBtu for natural gas and $91.21 per barrel for oil at December 31, 2012.

Our after-tax PV-10 was $7.5 billion at year-end 2014, $3.7 billion at year-end 2013, and $2.1 billion at year-end 2012. The increase in our after-tax PV-10 value in 2014 over 2013 was principally due to an increase in our reserves and higher average natural gas prices. The increase in our after-tax PV-10 value in 2013 over 2012 was principally due to an

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increase in our reserves and higher average natural gas prices. The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2014 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2014 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $9.5 billion, compared to $5.1 billion at year-end 2013 and $2.3 billion at year-end 2012.

We believe that the pre-tax PV-10 value of the estimated cash flows related to our estimated proved reserves is a useful supplemental disclosure to the after-tax PV-10 value. While pre-tax PV-10 is based on prices, costs and discount factors that are comparable from company to company, the after-tax PV-10 is dependent on the unique tax situation of each individual company. We understand that securities analysts use pre-tax PV-10 as one measure of the value of a company s current proved reserves and to compare relative values among peer companies without regard to income taxes. We refer you to Note 4 in the consolidated financial statements for a discussion of our standardized measure of discounted future cash flows related to our proved natural gas and oil reserves, to the risk factor Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate in Item 1A of Part I of this Annual Report, and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

At year-end 2014, 91% of our estimated proved reserves were natural gas and 55% of total estimated proved reserves were classified as proved developed, compared to 100% and 61%, respectively, in 2013 and 100% and 80%, respectively in 2012. We operate, or if operations have not commenced, plan to operate, approximately 97% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index approximated 14.0 years at year-end 2014. Natural gas sales accounted for nearly 100% of total operating revenues for the E&P segment in 2014, 2013 and 2012.

The following table provides an overall and categorical summary of our natural gas and oil reserves, as of fiscal year-end 2014 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2014 and sets forth 2014 annual information related to production and capital investments for each of our operating areas:

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2014 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

		Appalachia		Ark-La-Tex			
	Fayetteville Shale	Northeast	Southwest	East Texas	Arkoma Basin	New Ventures	Total
Estimated Proved Reserves:							
Natural Gas (Bcf):							
Developed (Bcf)	3,353	1,594	543	42	141	2	5,675
Undeveloped (Bcf)	1,716	1,598	819		1		4,134
	5,069	3,192	1,362	42	142	2	9,809
Crude Oil (MMBbls):							
Developed (MMBbls)			7.0			0.4	7.4
Undeveloped (MMBbls)			30.2				30.2
			37.2			0.4	37.6
Natural Gas Liquids (MMBbls):							
Developed (MMBbls)			38.5			0.1	38.6
Undeveloped (MMBbls)			80.1				80.1
			118.6			0.1	118.7
Total Proved Reserves (Bcfe)(1):							
Developed (Bcfe)	3,353	1,594	816	42	141	5	5,951
Undeveloped (Bcfe)	1,716	1,598	1,481		1		4,796
	5,069	3,192	2,297	42	142	5	10,747
Percent of Total	47%	30%	22%		1%		100%
Percent Proved Developed	66%	50%	36%	100%	99%	100%	55%
Percent Proved Undeveloped	34%	50%	64%		1%		45%
Production (Bcfe)	494	254	3	5	10	2	768
Capital Investments (millions)(2)	$944	$695	$5,012	$2	$3	$493	$7,149
Total Gross Producing Wells(3)	4,027	522	1,034	153	1,138	13	6,887
Total Net Producing Wells(3)	2,777	257	800	94	556	10	4,494
Total Net Acreage	764,287 (4)	266,073 (5)	413,376 (6)	48,292 (7)	228,789 (8)	4,181,044 (9)	5,901,861
Net Undeveloped Acreage	267,456 (4)	205,491 (5)	188,244 (6)	64 (7)	45,425 (8)	4,170,687 (9)	4,877,367
PV-10:							
Pre-tax (millions)(10)	$5,250	$2,120	$1,859	$55	$175	$(1)	$9,458
PV of taxes (millions)(10)	1,063	429	376	11	36		1,915

After-tax (millions)(10)	$4,187	$1,691	$1,483	$44	$139	$(1)	$7,543
Percent of Total	55%	22%	20%	1%	2%		100%
Percent Operated(11)	97%	98%	98%	97%	87%	100%	97%

(1) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. We used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

(2) Our Total and Fayetteville Shale capital investments exclude $105 million related to our drilling rig related equipment, sand facility and other equipment.

(3) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2014.

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(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 15,289 net acres in 2015, 921 net acres in 2016, and 779 net acres in 2017 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 35,215 net acres in 2015, 28,912 net acres in 2016 and 69,497 net acres in 2017.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 46,342 net acres in 2015, 41,184 net acres in 2016 and 44,256 net acres in 2017. Of this acreage, 16,876 net acres in 2015, 17,798 net acres in 2016 and 15,691 net acres in 2017 can be extended for an average of an additional 4.6 years.

(7) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 64 net acres in 2015, zero net acres in 2016 and zero net acres in 2017.

(8) Includes 123,442 net developed acres and 432 net undeveloped acres in the Arkoma Basin that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 15,332 net acres in 2015, 5,533 net acres in 2016 and 986 net acres in 2017.

(9) Assuming successful wells are not drilled to develop the acreage and leases are not extended, our leasehold expiring over the next three years, excluding New Brunswick, Canada, the Lower Smackover Brown Dense area and the Sand Wash Basin will be 143,109 net acres in 2015, 302,688 net acres in 2016 and 221,189 net acres in 2017. With regard to our acreage in New Brunswick, Canada, 2,518,518 net acres are scheduled to expire in March 2015. In February 2015, we requested an extension of our license agreement. With regard to our acreage in the LSBD, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 153,866 net acres in 2015, 60,078 net acres in 2016 and 17,057 net acres in 2017. With regard to our acreage in the Sand Wash Basin, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 107,963 net acres in 2015, 85,977 net acres in 2016, and 34,970 net acres in 2017.

(10) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company s proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved natural gas and oil reserves.

(11) Based upon pre-tax PV-10 of proved developed producing activities.

We refer you to Note 4 in our consolidated financial statements for a more detailed discussion of our proved natural gas and oil reserves as well as our standardized measure of discounted future net cash flows related to our proved natural gas and oil reserves. We also refer you to the risk factor Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate in Item 1A of Part I of this Annual Report and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

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Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2012, 2013 and 2014.

Changes in Proved Undeveloped Reserves (Bcfe)

		Appalachia		Ark-La-Tex		
	Fayetteville Shale	Northeast	Southwest	East Texas	Arkoma Basin	Total
December 31, 2011	2,415	170		27	21	2,633
Extensions, discoveries and other additions	32	305				337
Total revision attributable to performance and production	(239)	16				(223)
Price revisions	(1,401)	1		(26)	(7)	(1,433)
Developed	(443)	(50)				(493)
Disposition of reserves in place						
Acquisition of reserves in place						
December 31, 2012	364	442		1	14	821
Extensions, discoveries and other additions (1)	1,530	810				2,340
Total revision attributable to performance and production	(115)	(33)			(9)	(157)
Price revisions	18	26		1		45
Developed	(142)	(170)				(312)
Disposition of reserves in place						
Acquisition of reserves in place						
December 31, 2013	1,655	1,075		2	5	2,737
Extensions, discoveries and other additions (2)	573	589				1,162
Total revision attributable to performance and production (3)	(130)	307		(2)	(4)	171
Price revisions	24	11				35
Developed	(406)	(384)				(790)
Disposition of reserves in place						
Acquisition of reserves in place (4)			1,481			1,481
December 31, 2014	1,716	1,598	1,481		1	4,796

(1) The 2013 proved undeveloped reserve additions are primarily associated with the increase in gas prices.
(2) Primarily associated with the undeveloped locations that were added throughout the year in 2014 due to our successful drilling program.
(3) Primarily due to changes associated with the analysis of updated data collected in the year and decreases related to current year production.
(4) Our acquisition of reserves in place is attributable to the purchase of undeveloped locations in West Virginia and southwest Pennsylvania.

As of December 31, 2014, we had 4,796 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2014, we invested $767 million in connection with converting 790 Bcfe or 29% of our proved undeveloped reserves as of December 31, 2013, into proved developed reserves and added 2,643 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale and the Appalachian Basin. As of December 31, 2013, we had 2,737 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2013, we invested $248 million in connection with converting 312 Bcfe, or 38%, of our proved undeveloped reserves as of December 31, 2012 into proved developed reserves and added 2,340 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale and the Appalachian Basin. Our December 31, 2014 proved reserves include 181 Bcfe of proved undeveloped reserves from 60 locations that have a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties have a negative present value of $28 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves.

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The development of our proved undeveloped reserves will require us to make significant additional investments. We expect that the development costs for our proved undeveloped reserves of 4,796 Bcfe as of December 31, 2014 will require us to invest an additional $4.9 billion for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. A significant decrease in price levels for an extended period of time could result in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors A substantial or extended decline in natural gas and oil prices would have a material adverse effect on us, We may have difficulty financing our planned capital investments, which could adversely affect our growth and Our level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth in Item 1A of Part I of this Annual Report and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

The reserve replacement ratio measures the ability of an exploration and production company to add new reserves to replace the reserves that are being depleted by its current production volumes. The reserve replacement ratio, which we discuss below, is an important analytical measure used by investors and peers in the E&P industry to evaluate performance results and long-term prospects. There are limitations as to the usefulness of this measure, as it does not reflect the type of reserves or the cost of adding the reserves or indicate the potential value of the reserve additions.

In 2014, we replaced 591% of our production volumes with 1,693 Bcfe of proved reserve additions, net upward revisions of 543 Bcfe, and 2,304 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 531 Bcfe were proved developed and 1,162 Bcfe were proved undeveloped. In 2014, upward reserve revisions resulting from higher gas prices totaled 38 Bcf, 10 Bcf and 6 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had performance revisions in 2014 of (126) Bcf, 636 Bcf and (21) Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. Additionally, our reserves increased by 2,304 Bcfe in 2014 as a result of acquisitions primarily associated with acreage in Southwest Appalachia.

In 2013, we replaced 550% of our production volumes with 3,285 Bcfe of proved reserve additions, net upward revisions of 326 Bcfe, and 4 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 945 Bcfe were proved developed and 2,340 Bcfe were proved undeveloped. In 2013, upward reserve revisions resulting from higher gas prices totaled 191 Bcf, 35 Bcf and 21 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had upward performance revisions in 2013 of 16 Bcf, 62 Bcf and 1 Bcf in our Fayetteville Shale, Northeast Appalachia and New Ventures divisions, respectively. Additionally, our reserves increased by 4 Bcf in 2013 as a result of our acquisition of natural gas leases and wells.

In 2012, we replaced our production volumes with 920 Bcfe of proved reserve additions as a result of our drilling and acquisition program but also incurred net downward revisions of 2,088 Bcfe principally due to a decrease in the price of natural gas and to a lesser extent due to downward performance revisions of 336 Bcfe. Of the reserve additions, 583 Bcfe were proved developed and 337 Bcfe were proved undeveloped. The total downward reserve revisions were primarily impacted by the low commodity price environment in 2012 and to a lesser extent by downward performance revisions. In 2012, downward reserve revisions resulting from lower gas prices totaled 1,684 Bcf, 9 Bcf and 59 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had a net downward performance revision in 2012 of 362 Bcf and 10 Bcf in our Fayetteville Shale and Ark-La-Tex divisions, respectively. We had a net upward performance revision in 2012 of 36 Bcf in Northeast Appalachia. Additionally, our reserves decreased by 141 Bcfe in 2012 as a result of our disposition of natural gas leases and wells.

For the period ended December 31, 2014, our three-year average reserve replacement ratio, including revisions and acquisitions, was 351%. Our reserve replacement ratio for 2014, excluding reserve revisions, was 520%, compared to 501% in 2013 and 163% in 2012. Excluding reserve revisions and acquisitions, our three-year average reserve replacement ratio was 296%.

Since 2005, the substantial majority of our reserve additions have been generated from our Fayetteville Shale division. However, over the past several years, Northeast Appalachia has also contributed to an increasing amount of our reserve additions, totaling 836 Bcf, 1,200 Bcf and 500 Bcf in 2014, 2013 and 2012, respectively. Additionally, our reserves increased by 2,304 Bcfe in 2014 as a result of acquisitions primarily associated with acreage in Southwest Appalachia. We expect our drilling programs in the Fayetteville Shale, Northeast Appalachia, and Southwest Appalachia to continue to be the primary source of our reserve additions in the future; however, our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors Our drilling plans are subject to change and Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted

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returns in Item 1A of Part I of this Annual Report and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Operations

Fayetteville Shale

Our Fayetteville Shale properties are one of the primary focus areas of our exploration and production business. The Fayetteville Shale is a Mississippian-age unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 550 feet and ranging in depth from 1,500 to 6,500 feet. As of December 31, 2014, we held leases for approximately 888,161 net acres in the play area (267,456 net undeveloped acres, 496,831 net developed acres held by Fayetteville Shale production, 123,442 net acres held by conventional production in the Arkoma Basin, and 432 net undeveloped acres in the Arkoma Basin), compared to approximately 905,684 net acres at year-end 2013 and 913,502 net acres at year-end 2012.

Approximately 5,069 Bcf of our reserves at year-end 2014 were attributable to our Fayetteville Shale properties, compared to approximately 4,795 Bcf at year-end 2013 and 2,988 Bcf at year-end 2012. Our reserves in the Fayetteville Shale increased by 274 Bcf in 2014, which included reserve additions of 856 Bcf, net upward price revisions of 38 Bcf, 126 Bcf of net downward revisions due to well performance, offset by production of 494 Bcf. Our net production from the Fayetteville Shale was 494 Bcf in 2014, compared to 486 Bcf in both 2013 and 2012. In 2015, we estimate our net production from the Fayetteville Shale will be in the range of 448 to 453 Bcf.

At year-end 2014, after excluding our acreage in the conventional Arkoma Basin and the federal acreage we hold in the Ozark Highlands Unit, approximately 85% of our 580,060 total net leasehold acres remaining in the Fayetteville Shale was held by production. For more information about our acreage and well count, we refer you to Properties in Item 2 of Part 1 of this Annual Report. Excluding our acreage in the conventional Arkoma Basin, our acreage position was obtained at an average cost of approximately $320 per acre and has an average royalty interest of 15%. In 2015, we expect to earn 4 sections, or approximately 1,422 net acres, representing 1% of our drilling program. As of December 31, 2014, excluding our acreage in the conventional Arkoma Basin and our federal acreage, the undeveloped portion of our acreage had an average remaining lease term of 6 months. We refer you to the risk factor If we fail to drill all of the wells that are necessary to hold our acreage, the initial lease terms could expire, which would result in the loss of certain leasehold rights in Item 1A of Part I of this Annual Report.

Following the commencement of two court actions, now consolidated, alleging deficiencies in the Environmental Impact Statement issued in connection with the grant of the leases by the Bureau of Land Management (BLM) in the Ozark National Forest, the BLM has discontinued approval of operational permits in the forest, including permits to drill, pending resolution of the litigation. The Ozark Highlands Unit lies entirely within the Ozark National Forest. Although the Company is not a party to the litigation and the plaintiffs complaints do not seek invalidation of the leases, we currently are unable to obtain permits to drill on the 158,231 acres we have leased in the unit and the national forest.

As of December 31, 2014, we had spud a total of 4,578 wells in the Fayetteville Shale since its commencement in 2004, of which 4,002 were operated by us and 576 were outside-operated wells. Of these wells, 468 were spud in 2014, 527 in 2013 and 491 in 2012. All of the wells spud in 2014 were designated as horizontal wells. At year-end 2014, 3,742 wells operated by the Company had been drilled and completed overall, including 3,651 horizontal wells. Of the 3,651 horizontal wells, 3,633 wells were fracture stimulated using either slickwater or crosslinked gel stimulation treatments, or a combination thereof.

In 2014, the horizontal wells we drilled as operator had an average completed well cost of $2.6 million per well, average horizontal lateral length of 5,440 feet, and an average time to drill to total depth of 6.8 days from re-entry to re-entry, which includes the downtime associated with the delivery and operational start up of seven new rigs which are expected to decrease drilling times in 2015 and beyond as the technological enhancements on these rigs is utilized. This compares to an average completed operated well cost of $2.4 million per well, average horizontal lateral length of 5,356 feet and average time to drill to total depth of 6.2 days from re-entry to re-entry during 2013. In 2012, our average completed operated well cost was $2.5 million per well with an average horizontal lateral length of 4,833 feet and average time to drill to total depth of 6.7 days from re-entry to re-entry. The operated wells we placed on production during 2014 averaged initial production rates of 4,430 Mcf per day, compared to average initial production rates of 4,041 Mcf per day in 2013 and 3,629 Mcf per day in 2012. In 2014 and 2013, our initial production rates increased compared to 2013 and 2012, respectively, as a result of longer lateral lengths, improved well bore placement, and further refined completion and flowback techniques. During 2014, we placed 145 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, compared to 93 wells in 2013 and 59 wells in 2012.

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Our total proved net reserves in the Fayetteville Shale at year-end 2014 were from a total of 5,445 locations, of which 4,045 were proved developed producing, 187 were proved developed non-producing and 1,213 were proved undeveloped. Of the 5,445 locations, 5,373 were horizontal. The average gross proved reserves for the undeveloped wells included at year-end 2014 was approximately 2.3 Bcf per well, compared to 2.5 Bcf per well at year-end 2013, and 2.8 Bcf per well at year-end 2012. The decrease in average gross proved reserves for our undeveloped wells in 2014 was primarily due to the addition of proven undeveloped locations in areas of the field with lower estimated ultimate recoveries. The decrease in average gross proved reserves for our undeveloped wells in 2013 was primarily due to the addition of over 800 proven undeveloped locations with lower estimated ultimate recoveries that were added due to the higher gas price environment. Total proved net natural gas reserves in the Fayetteville Shale in 2013 were approximately 4,795 Bcf from a total of 4,631 locations, of which 3,511 were proved developed producing, 59 were proved developed non-producing and 1,061 were proved undeveloped. Total proved net natural gas reserves in the Fayetteville Shale in 2012 totaled approximately 2,988 Bcf from a total of 3,508 locations, of which 3,175 were proved developed producing, 123 were proved developed non-producing and 210 were proved undeveloped.

In 2014, we invested approximately $944 million in the Fayetteville Shale, which included approximately $838 million to spud 468 wells, 464 of which we operate. Included in our total capital investments in the Fayetteville Shale during 2014 was $99 million in capitalized costs and other expenses and $7 million for acquisition of properties. In 2013, we invested approximately $907 million in the Fayetteville Shale, which included $804 million to spud 527 wells, 504 of which we operate, $97 million in capitalized costs and other expenses and $6 million for acquisition of properties. In 2012, we invested approximately $991 million in the Fayetteville Shale, which included $877 million to spud 491 wells, 453 of which we operate, $110 million in capitalized costs and other expenses and $4 million for acquisition of properties. As of December 31, 2014, we had acquired approximately 1,324 square miles of 3-D seismic data, which provides us with seismic data on approximately 65% of our net acreage position in the Fayetteville Shale, excluding our acreage in the Arkoma Basin.

In 2015, we plan to invest approximately $560 million in our Fayetteville Shale properties, which includes participating in approximately 225 to 235 gross wells, all of which we plan to operate.

We believe that our Fayetteville Shale acreage continues to have significant development potential. Our strategy is to continue our development drilling, increase the amount of acreage we hold by production and determine the economic viability of the undrilled portion of our acreage. Our drilling program with respect to our Fayetteville Shale properties is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods and well spacing, the extent to which we can replicate the results of our most successful Fayetteville Shale wells in other Fayetteville Shale acreage and the natural gas commodity price environment. As we continue to gather data about the Fayetteville Shale, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor Our drilling plans are subject to change in Item 1A of Part I of this Annual Report.

Northeast Appalachia

We began leasing acreage in northeastern Pennsylvania in 2007 in an effort to participate in the emerging Marcellus Shale. As of December 31, 2014, we had approximately 266,073 net acres in Northeast Appalachia under which we believe the Marcellus Shale is present (205,491 net undeveloped acres and 60,582 net developed acres held by production), compared to approximately 292,446 net acres at year-end 2013 and 176,298 net acres at year-end 2012. Our undeveloped acreage position as of December 31, 2014 had an average remaining lease term of 2.5 years and an average royalty interest of 15% and was obtained at an average cost of approximately $1,189 per acre. In January 2015, we closed on an agreement to purchase certain oil and gas assets covering approximately 46,700 net acres in northeast Pennsylvania from WPX for $288 million, subject to customary post-closing adjustments. At closing, this acreage was producing approximately 50 million net cubic feet of gas per day from 63 operated horizontal wells. In connection with this acquisition, we assumed firm transportation capacity of 260 million cubic feet of gas per day predominantly on the Millennium pipeline. The acquired acreage is near our existing acreage in Northeast Appalachia.

As of December 31, 2014, we had spud 376 operated wells, 255 of which were on production and 367 of which are horizontal wells. In 2014, we invested approximately $695 million in Northeast Appalachia and spud 99 operated horizontal wells and acquired 5 horizontal and 2 vertical wells, resulting in reserve additions and revisions of 1,483 Bcf. Our reserves in Northeast Appalachia increased by 1,229 Bcf in 2014, which included reserve additions of 834 Bcf, 636 Bcf of net upward revisions due to well performance, net upward price revisions of 10 Bcf, and acquisitions of 2 Bcf, offset by production of 254 Bcf. Of the 104 horizontal wells, 61 wells are located in Susquehanna County, 32 wells are located in Bradford County, 4 wells are located in Lycoming County, 3 wells are located in Tioga County, 3 wells are located in Wyoming County and the remaining 1 well is located in Sullivan County. In 2014, our operated horizontal wells had an average completed well cost of $6.1 million per well, average horizontal lateral length of 4,752 feet and an average of 15 fracture stimulation stages. This compares to an average completed operated well cost of $7.0 million per well, average horizontal lateral length of 4,982 feet and an average of 18 fracture stimulation stages in 2013. In 2012, our average completed operated well cost was $6.1 million per well with an average horizontal lateral length of 4,070 feet and an average of 12 fracture stimulation stages. Included in our total capital investments in Northeast Appalachia during 2014 was approximately $571 million for drilling and completions, $28 million for acquisition of properties, $25 million for seismic and $71 million in facilities, capitalized costs and other expenses. In 2013, we invested approximately $872 million in Northeast Appalachia and spud 108 operated wells, resulting in reserve additions and revisions of 1,297 Bcf. In 2012, we invested approximately $507 million in Northeast Appalachia and spud 92 operated wells, resulting in net reserve additions and revisions of 500 Bcf.

Approximately 3,192 Bcf of our total proved net reserves at year-end 2014 were attributable to Northeast Appalachia. We had a total of 254 horizontal and one vertical well that we operated and that were on production as of December 31, 2014, resulting in net production from this area of 254 Bcf in 2014, compared to 151 Bcf in 2013 and 54 Bcf in 2012. Our 2014 year-end reserves in Northeast Appalachia include a total of 737 locations, of which 524 were proved developed producing, 13 were proved developed non-producing and 200 were proved undeveloped. At year-end 2013, we had approximately 1,963 Bcf in proved reserves in Northeast Appalachia from a total of 522 locations, of which 333 were proved developed producing, and 189 were proved undeveloped. At year-end 2012, we had approximately 816 Bcf of proved reserves in Northeast Appalachia from a total of 203 locations, of which 129 were proved developed producing, 1 was proved developed non-producing and 73 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2014 was approximately 9.6 Bcf per well, compared to 6.9 Bcf per well at year-end 2013 and 7.6 Bcf per well in 2012.

In 2015, we plan to invest approximately $700 million in Northeast Appalachia (excluding the purchase price for the additional 46,700 net acres in the WPX Acquisition) and expect to participate in a total of 88 to 92 gross wells in 2015, the vast majority of which will be operated by us. In 2015, we estimate our net production from Northeast Appalachia will be in the range of 356 to 361 Bcf. Our ability to bring our Northeast Appalachia production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to Midstream Services in Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Northeast Appalachia production and to the risk factor Our ability to sell our natural gas and oil and to receive market prices for our production may be adversely affected by constraints or interruptions on gathering systems, pipelines, processing and transportation systems owned or operated by us or others. in Item 1A of Part I of this Annual Report.

We believe that our Northeast Appalachia acreage has significant development potential. Our drilling program with respect to Northeast Appalachia is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods, transportation capacity and well spacing and the natural gas commodity price environment. As we continue to gather data about Northeast Appalachia, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor Our drilling plans are subject to change in Item 1A of Part I of this Annual Report.

Southwest Appalachia

In December 2014, we closed a transaction to acquire oil and gas assets in West Virginia and southwest Pennsylvania for approximately $5.0 billion. This acreage has at least three drilling objectives, namely the Marcellus, Utica and Upper Devonian Shales. As of December 31, 2014, we had approximately 413,376 net acres in Southwest Appalachia (188,244 net undeveloped acres and 225,132 net developed acres held by production). Our undeveloped acreage position as of December 31, 2014 had an average remaining lease term of 3 years and an average net revenue interest of 86%.

Approximately 2,297 Bcfe of our total proved net reserves at year-end 2014 were attributable to Southwest Appalachia. These proved reserves are substantially attributable to the Marcellus Shale (2,260 Bcfe) with the remaining difference attributable to the Utica Shale and shallower reservoirs associated with historic vertical wells. We had a total of 255 horizontal and 667 vertical wells that we operated and that were on production as of December 31, 2014. Additionally, there were 42 horizontal wells in progress at the end of 2014. Our 2014 year-end reserves in Southwest Appalachia include a total of 1,502 locations, of which 1,034 were proved developed producing, 124 were proved developed non-producing and 344 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2014 was approximately 8.4 Bcfe per well.

In 2015, we plan to invest approximately $520 million in Southwest Appalachia (excluding the purchase price for the additional 30,000 net acres in the Statoil Property Acquisition) and expect to participate in a total of 50 to 55 gross wells in

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2015, most of which will be operated by us. In 2015, we estimate our net production from Southwest Appalachia will be in the range of 136 to 141 Bcfe. Our ability to bring our Southwest Appalachia production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to Midstream Services within Item1 of this Annual Report for a discussion of our gathering and transportation arrangements for Southwest Appalachia production and to the risk factor Our ability to sell our natural gas and oil and to receive market prices for our production may be adversely affected by constraints or interruptions on gathering systems, pipelines, processing and transportation systems owned or operated by us or others. in Item 1A of Part I of this Annual Report.

We believe that our Southwest Appalachia acreage has significant development potential. Our drilling program with respect to Southwest Appalachia is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods, transportation capacity and well spacing and the natural gas commodity price environment. As we continue to gather data about Southwest Appalachia, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor Our drilling plans are subject to change in Item 1A of Part I of this Annual Report.

New Ventures

We actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as New Ventures. We have been focusing on both natural gas and oil unconventional plays, and the technological methods best suited to developing these plays, such as horizontal drilling and fracture stimulation techniques. New Ventures prospects are evaluated based on multi-well potential and land availability as well as other criteria and may be located both inside and outside of the United States. As of December 31, 2014, we held 4,170,687 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres were located in New Brunswick, Canada. This compares to 3,972,732 net undeveloped acres held at year-end 2013 and 3,819,128 net undeveloped acres held at year-end 2012.

Although we believe that our New Ventures projects have significant exploration and exploitation potential, there can be no assurance that any prospects will result in viable projects or that we will not abandon our initial investments. We refer you to the risk factors The success of our New Ventures projects is subject to drilling and completion technique risks and enhanced recovery methods. Our drilling results may not meet our expectations for reserves or production and the value of our undeveloped New Venture acreage could decline, and Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns in Item 1A of Part I of this Annual Report.

Sand Wash Basin. In 2014, we acquired approximately 376,497 net acres in northwest Colorado targeting crude oil, NGLs and natural gas contained in the Sand Wash Basin. Testing of the play commenced in the second half of the year with us drilling four vertical wells and one horizontal well. Results have been encouraging to date and we intend to continue to test the play in 2015.

Brown Dense. In July 2011, we announced that we would begin testing a new unconventional liquids rich play targeting the Brown Dense formation, an unconventional reservoir that ranges in vertical depths from 8,000 to 11,000 feet and appears to be laterally extensive over a large area ranging in thickness from 300 to 550 feet. As of December 31, 2014, we held approximately 304,371 net acres in the area, obtained at an average cost of $831 per acre. Our leases currently have an approximate 81% average net revenue interest and an average primary lease term of approximately three years, which may be extended for approximately three to four additional years.

As of December 31, 2014, we had drilled 14 operated wells in the area, 6 of which were currently producing. Late in 2014, the Company acquired 75 miles of 3-D seismic data and is currently in the process of analyzing that data and our results to date.

New Brunswick, Canada. In March 2010, we successfully bid for exclusive licenses from the Department of Natural Resources of New Brunswick to search and conduct an exploration program covering 2,518,518 net acres in the province in order to test new hydrocarbon basins. As a condition under our licenses, we are required to make investments of approximately $47 million Canadian dollars in the province by March 2015. In order to obtain the licenses, we provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $45 million Canadian dollars. The promissory notes secure our capital expenditure obligations under the licenses and are returnable to us to the extent we perform such obligations. If we fail to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. Through December 31, 2014, we have invested approximately $45 million Canadian dollars, or $44 million USD, in our New Brunswick exploration program toward our commitment, fully covering the promissory notes held by the Province of New Brunswick.

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Our licenses are scheduled to expire in March 2015. The newly elected provincial government in New Brunswick recently announced an intent to impose a moratorium on hydraulic fracturing until a list of conditions is met and has introduced authorizing legislation in the provincial legislature. We have applied for an extension of our licenses past the end of the moratorium, but as of this time that extension has not been granted. The list of conditions that the provincial government has announced is subjective, and we cannot predict the duration of the moratorium or whether we will be granted the extension requested or any other extension. Unless and until the moratorium is lifted and our licenses are extended, we will not be able to continue with our program in New Brunswick. If this extension is not granted, we may be required to write off our investment.

Acquisitions

In December 2014, we acquired approximately 413,000 net acres in West Virginia and southwest Pennsylvania with plans to target the Marcellus, Utica and Upper Devonian Shales for approximately $5.0 billion. Additionally, in January 2015, we acquired an additional approximate 30,000 net acres in this area for $365 million.

Also, in January 2015, we acquired approximately 46,700 net acres in northeast Pennsylvania for $288 million. As part of this transaction, we also received firm transportation capacity of 260 million cubic feet per day predominately on the Millennium pipeline.

In March 2014 and July 2014, we acquired approximately 380,000 net acres in northwest Colorado principally in the Sand Wash basin for approximately $215 million.

In April 2013, we acquired approximately 162,000 net acres in Northeast Appalachia for approximately $82 million. The acquired acreage is near our existing acreage in Northeast Appalachia.

Capital Investments

During 2014, we invested a total of approximately $7.3 billion in our E&P business and participated in drilling 576 wells, 280 of which were successful and 296 of which were in progress at year-end. Of the 296 wells in progress at year-end, 224 and 71 were located in our Fayetteville Shale and Northeast Appalachia operating areas, respectively. Additionally, we had 42 wells in progress in Southwest Appalachia at the end of 2014. Of the approximately $7.3 billion invested in our E&P business in 2014, approximately $944 million was invested in the Fayetteville Shale, $695 million in Northeast Appalachia, $5.0 billion in Southwest Appalachia, $2 million in East Texas, $3 million in our conventional Arkoma Basin program and $493 million in New Ventures projects, which includes $115 million in the Brown Dense and $288 million in the Sand Wash Basin.

Of the $7.3 billion invested in 2014, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $5.3 billion for acquisition of properties, $247 million in capitalized interest and other expenses and $56 million for seismic expenditures. Additionally, we invested approximately $105 million in our drilling rigs and related equipment, sand facility and other equipment, and $5 million in pond and water facilities. In 2013, we invested approximately $2.1 billion in our primary E&P business activities and participated in drilling 653 wells. Of the $2.1 billion invested in 2013, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $224 million in capitalized interest and other expenses, $159 million for acquisition of properties, and $28 million for seismic expenditures. Additionally, we invested approximately $76 million in our drilling rigs and related equipment, sand facility and other equipment, and $18 million in pond and water facilities. In 2012, we invested approximately $1.9 billion in our primary E&P business activities and participated in drilling 595 wells. Of the $1.9 billion invested in 2012, approximately $1.4 billion was invested in exploratory and development drilling and workovers, $186 million for acquisition of properties, $10 million for seismic expenditures and $254 million in capitalized interest and other expenses. Additionally, we invested approximately $15 million in our drilling rig related equipment, sand facility and other equipment.

In 2015, excluding the capital associated with the closing of the WPX and Statoil Property Acquisitions, we plan to invest approximately $1.9 billion in our E&P program and participate in drilling 363 to 382 gross wells, the vast majority of which will be operated by us. The Fayetteville Shale, Northeast Appalachia and Southwest Appalachia will be the primary focus of our capital investments, with planned investments of approximately $560, $700, and $520 million, respectively. Our planned 2015 capital investments also include approximately $110 million in the Sand Wash Basin, the Brown Dense and other New Ventures projects.

Of the $1.9 billion allocated to our 2015 E&P capital budget, approximately $1.4 billion currently is planned to be invested in development and exploratory drilling, $17 million in seismic and other geological and geophysical expenditures, $72 million in acquisition of properties and $391 million in capitalized interest and expenses as well as equipment, facilities and technology-related expenditures. Additionally, we plan to invest $31 million in our E&P services which support our E&P operations. The planned capital program for 2015 is flexible and can be modified. We will reevaluate our proposed investments as needed to take into account prevailing market conditions and, if natural gas prices are challenged in 2015, we could change our planned investments. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Investments within Item 7 of Part II of this Annual Report for additional discussion of the factors that could impact our planned capital investments in 2015.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 2,105 MMcfe in 2014, compared to 1,800 MMcfe in 2013 and 1,544 MMcfe in 2012. Total natural gas equivalent production was 768 Bcfe in 2014, up from 657 Bcfe in 2013 and 565 Bcfe in 2012. Our natural gas production was 766 Bcf in 2014, compared to 656 Bcf in 2013 and 565 Bcf in 2012. The increase in production in 2014 resulted primarily from a 103 Bcf increase in net production from our Northeast Appalachia properties, a 3 Bcfe increase in net production from our Southwest Appalachia properties, and an 8 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 3 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The increase in production in 2013 resulted primarily from a 97 Bcf increase in net production from our Northeast Appalachia properties, a 1 Bcfe increase in net production from our New Ventures properties, and a 1 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 7 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. We produced 235,000 barrels of oil in 2014, compared to 138,000 barrels of oil in 2013 and 83,000 barrels of oil in 2012. Our oil production has increased between 2014 and 2013 primarily due to the acquisition of oil and gas properties in Southwest Appalachia and our exploration activities in the Brown Dense. In 2014, we produced 231,000 barrels of NGLs, compared to 50,000 barrels of NGLs in 2013, primarily due to the acquisition of oil and gas properties in West Virginia and our exploration activities in the Brown Dense. For 2015, we are targeting total net natural gas, oil and NGL production of approximately 940 to 955 Bcfe, which represents a growth rate of approximately 23% over our 2014 production volumes, using midpoints.

Sales of natural gas and oil production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand for our production. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production to support certain desired levels of cash flow and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. As of December 31, 2014, we had New York Mercantile Exchange, or NYMEX, commodity price hedges in place on 240 Bcf, or approximately 27% of our targeted 2015 natural gas production. We intend to hedge additional future production volumes to the extent natural gas prices rise to levels that we believe will achieve certain desired levels of cash flow. We refer you to Item 7A of this Annual Report, Quantitative and Qualitative Disclosures about Market Risks, for further information regarding our hedge position as of December 31, 2014.

Including the effect of hedges, we realized an average wellhead price of $3.72 per Mcf for our natural gas production in 2014, compared to $3.65 per Mcf in 2013 and $3.44 per Mcf in 2012. Our hedging activities decreased our average realized natural gas sales price by $0.02 per Mcf in 2014, compared to increases of $0.48 per Mcf in 2013 and $1.10 per Mcf in 2012. Our average oil price realized was $79.91 per barrel in 2014, compared to $103.32 per barrel in 2013 and $101.54 per barrel in 2012. Our average realized NGL price was $15.72 per barrel in 2014 compared to $43.63 per barrel in 2013. None of our oil or NGL production was hedged during 2014, 2013 or 2012.

During 2014, the average price received for our natural gas production, excluding the impact of hedges, was approximately $0.67 per Mcf lower than average NYMEX prices. Differences between NYMEX and price realized are due primarily to locational differences and transportation cost. Assuming a NYMEX commodity price for 2015 of $3.25 per Mcf of natural gas, we expect to receive an average sales price for our natural gas production $0.70 to $0.85

per Mcf below the NYMEX Henry Hub average monthly settlement price, including the impact of financial basis hedges. This discount to NYMEX includes average third-party transportation charges in the range of $0.35 to $0.40 per Mcf and average fuel charges in the range of .50% to 1.0% of our sales price for natural gas and basis differential. As of December 31, 2014, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 292 Bcf and 139 Bcf of our 2015 and 2016 production, respectively, and expected natural gas production through financial hedging activities and physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.13) per Mcf and ($0.08) per Mcf for 2015 and 2016, respectively.

Delivery Commitments. As of December 31, 2014, we had natural gas delivery commitments of 452 Bcf in 2015 and 194 Bcf in 2016 under existing agreements. These amounts are well below our forecasted 2015 natural gas production of approximately 875 to 890 Bcf from our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia divisions and anticipated 2016 production from our available reserves in our Fayetteville Shale, Northeast Appalachia and Southwest

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Appalachia divisions, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our contractual obligations other than those discussed in Item 1A. Risk Factors of Part I of this Annual Report. We expect to be able to fulfill all of our short-term or long-term contractual obligations to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

Customers. Our customers include major energy companies, utilities and industrial purchasers of natural gas. During the years ended December 31, 2014, 2013 and 2012, no single third-party purchaser accounted for 10% or more of our consolidated revenues.

Competition

All phases of the natural gas and oil industry are highly competitive. We compete in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and oil and the securing of labor and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to us.

Competition in Arkansas has increased in recent years due largely to the development of improved access to interstate pipelines and our discovery of the Fayetteville Shale. Although improved intrastate and interstate pipeline transportation in Arkansas has increased our access to markets for our natural gas production, these markets are also served by a number of other suppliers. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. Outside Arkansas, we face competition from a large number of other producers. We also face competition for pipeline and other services to transport our product in to market, particularly in the Northeastern United States.

We cannot predict whether and to what extent any market reforms initiated by the Federal Energy Regulatory Commission, or the FERC, or any new energy legislation will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas production is sold. However, we do not believe that we will be disproportionately or regulatory affected as compared to other natural gas and oil producers and marketers by any action taken by the FERC or any other legislative body.

Regulation

The exploration and development of natural gas and oil resources and the transportation and sale of production historically have been heavily regulated. For example, state governments regulate the location of wells and establish the minimum size for spacing units. Permits typically are required before drilling. State and local government zoning and land use regulations may also limit the locations for drilling and production. Similar regulations can also affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services may require licensing.

Currently in the United States, the price at which natural gas or oil may be sold is not regulated. Congress has imposed price regulation from time to time, and there can be no assurance that the current, less stringent regulatory approach will continue. The federal government prohibits the export of crude oil with limited exceptions and requires permits to export natural gas. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act and the rules that the Commodities Futures Trading Commission, or the CFTC, and the SEC have issued under it regulate certain futures and options contracts in the major energy markets, including for natural gas and oil. These regulations require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with our derivative activities.

The exploration and development of natural gas and oil is also subject to extensive environmental regulation. We refer you to Other Environmental Regulation in Item 1 of Part 1 of this Annual Report and the risk factor We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Midstream Services

We believe our Midstream Services segment is well-positioned to complement our E&P initiatives and to compete with other midstream providers for unaffiliated business. We generate revenue from gathering fees associated with the transportation of natural gas to market and through the marketing of natural gas. Our gathering assets support our E&P

operations and are currently concentrated in the Fayetteville Shale in Arkansas and Northeast Appalachia in Pennsylvania. We plan to divest our Northeast Appalachia gathering assets in 2015.

Our operating income from this segment was $361 million on revenues of $4.4 billion in 2014, compared to $325 million on revenues of $3.3 billion in 2013 and $294 million on revenues of $2.4 billion in 2012. Revenues increased in 2014 and 2013 primarily due to an increase in the prices received for volumes marketed and an increase in volumes marketed. Adjusted EBITDA generated by our Midstream Services segment was $418 million in 2014, compared to $377 million in 2013 and $339 million in 2012. The increases in 2014 and 2013 operating income and Adjusted EBITDA were primarily due to increased gathering revenues, partially offset by increased operating costs and expenses. Adjusted EBITDA is a non-GAAP measure. We refer you to Management s Discussion and Analysis in Item 1 of Part I of this Annual Report for a table that reconciles Adjusted EBITDA to net income (loss).

Gas Gathering

We engage in gas gathering activities primarily in Arkansas related to the development of our Fayetteville Shale asset and in Pennsylvania related to the development of our Northeast Appalachia asset. In 2014, we invested approximately $144 million related to these activities and had gathering revenues of $562 million, compared to $158 million invested and revenues of $516 million in 2013 and $165 million invested and revenues of $474 million in 2012.

We continue to expand our network of gathering lines and facilities throughout the Fayetteville Shale area. During 2014, we gathered approximately 812 Bcf of natural gas in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party operated wells. During 2013, we gathered approximately 790 Bcf of natural gas volumes in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party operated wells. In 2012, we gathered approximately 781 Bcf of natural gas volumes in the Fayetteville Shale area, including 56 Bcf of natural gas from third-party wells. At the end of 2014, we had approximately 2,017 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 590,975 horsepower had been installed at 63 central point gathering facilities in the Fayetteville Shale.

We also engage in gathering activities in Pennsylvania, Louisiana and East Texas. During 2014, we gathered approximately 151 Bcf of natural gas volumes in Northeast Appalachia, Louisiana and East Texas. During 2013, we gathered approximately 110 Bcf of natural gas in Northeast Appalachia and East Texas. In 2012, we gathered approximately 65 Bcf of natural gas in Northeast Appalachia and East Texas. The increase in volumes gathered over the past three years was primarily due to our growing production volumes in Northeast Appalachia. At year-end 2014, we had approximately 105 miles of pipe in Pennsylvania, 25 miles of pipe in Texas and 16 miles of pipe in Louisiana. As of December 31, 2014, compression equipment representing in aggregate approximately 53,035 horsepower had also been installed at 4 central point gathering facilities in Pennsylvania. We plan to divest of our Northeast Appalachia gathering assets in 2015.

Gas Marketing

We attempt to capture downstream opportunities related to marketing and transportation of natural gas. Our current marketing strategy primarily involves the marketing of our own natural gas production. Additionally, we manage portfolio and basis risk, acquire transportation rights on third-party pipelines and in limited circumstances, purchase third-party natural gas. During 2014, we marketed 904 Bcf of natural gas, compared to 800 Bcf in 2013 and 676 Bcf in 2012. Of the total volumes marketed, production from our affiliated E&P operations accounted for 97% in 2014, compared to 96% in 2013 and 95% in 2012.

Fayetteville Shale Marketing

We are a foundation shipper on two pipeline projects serving the Fayetteville Shale. The Fayetteville Express Pipeline LLC, or FEP, is a 2.0 Bcf per day pipeline that is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. FEP was placed in service in January 2011. We have a maximum aggregate commitment of approximately 1,200,000 Dekatherms per day for an initial term of ten years from the in-service date. Texas Gas Transmission, LLC or Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP, constructed two pipeline laterals called the Fayetteville and Greenville Laterals, which also provide transportation for our Fayetteville Shale gas. We have maximum aggregate commitments of approximately 800,000 Mcf per day on the Fayetteville Lateral and 640,000 Mcf per day on the Greenville Lateral.

The Fayetteville and the Greenville Laterals and the FEP allow us to transport our natural gas to interconnecting pipelines that offer connectivity and marketing options to the eastern half of the United States. These interconnecting pipelines include Centerpoint, Natural Gas Pipeline, Mississippi River Transmission, Gulf South, Texas Gas, Tennessee

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Gas Pipeline, Trunkline, ANR, Columbia Gulf, Texas Eastern, and Sonat. We rely in part upon the Fayetteville and Greenville Laterals and the FEP to service our production from the Fayetteville Shale.

Northeast Appalachia

During 2011 and 2012, we entered into a number of short- and long-term firm transportation service agreements in support of our growing Northeast Appalachia operations in Pennsylvania. In March 2011, we entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which we entered into short- and long-term firm natural gas transportation services on Millennium s existing system. Expansions of the system were placed in-service in the second quarter of 2013 and the second quarter of 2014.

We have also executed firm transportation agreements with Tennessee Gas Pipeline Company (TGP), a subsidiary of Kinder Morgan Energy Partners, L.P., that increase our ability to move our Northeast Appalachia natural gas production in the short term to market as well as a precedent agreement for an expansion project that was placed in-service in November 2013 pursuant to which SES has subscribed for approximately 100,000 Dekatherms per day of capacity. TGP s expansion project will expand its 300 Line in Pennsylvania to provide natural gas transportation from the northeast Appalachia supply area to existing delivery points on the TGP system.

In March 2012, we entered into a precedent agreement with Constitution Pipeline Co. LLC for a proposed 121-mile pipeline connecting to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, New York. Subject to the receipt of regulatory approvals and satisfaction of other conditions, we agreed to enter a 15-year firm transportation agreement with a total capacity of approximately 150,000 Mcf per day on this project. Constitution Pipeline Co. LLC has extended the range for the pipeline s target in-service date to late 2015 through 2016 as a result of a longer than expected regulatory and permitting process. We have provided certain guarantees of a portion of our obligations under these agreements.

In May 2013, we entered into a precedent agreement with Columbia Gas Transmission, LLC for a project that will expand their existing system from Chester County, Pennsylvania to various interconnects throughout Pennsylvania, New Jersey, Maryland, and Virginia. Our volume on this project is 72,000 Mcf per day and it is expected to be in service by the third quarter of 2015.

In January 2014, we entered into a precedent agreement with Transcontinental Gas Pipeline Company LLC that will provide additional firm transportation capacity for supplies of natural gas from northern Pennsylvania to markets along the Transco pipeline system stretching from the northeastern US in Transco s Zone 6, to Zone 5 and terminating in Zone 4. Subject to the receipt of regulatory approvals and satisfaction of other conditions, we agreed to enter a 15-year firm transportation agreement with a total capacity of approximately 44,000 Mcf per day on this project and is expected to be in service in the second half of 2017.

In January 2015, we completed the purchase of certain oil and gas assets in northeast Pennsylvania and assumed short and long-term natural gas transportation agreements with Millennium Pipeline Company, L.L.C. with a total capacity of approximately 260,000 Mcf per day.

Southwest Appalachia

As part of our December 2014 acquisition of oil and gas assets in West Virginia and southwest Pennsylvania, we were assigned approximately 92,000 Mcf per day of capacity on the Columbia Gas Transmission pipeline. Additionally, we were assigned a precedent agreement with ET Rover Pipeline LLC for approximately 200,000 Mcf per day of capacity. ET Rover Pipeline LLC is constructing a new interstate pipeline to receive and transport natural gas from Marcellus and Utica production outlets to points of interconnection with Panhandle Eastern Pipe Line Company and

ANR Pipeline, to interconnections in Michigan, to the Union Gas Dawn Hub and to certain off-system delivery points on Trunkline Zone 1A, and is anticipated to be in service by the second quarter 2017.

In addition to the December 2014 assignment of natural gas transportation agreements, we were assigned certain ethane transportation agreements that allow for the transport of our ethane production to both domestic and international markets.

Demand Charges

As of December 31, 2014, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $5.4 billion and the Company has guarantee obligations of up to $173 million of that amount.

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We refer you to the risk factor If our Fayetteville Shale and Northeast Appalachia drilling programs fail to produce our projected supply of natural gas, the value of our investments in our gathering operations could be diminished. In addition, our commitments for transportation on third-party pipelines and gathering systems could make the sale of our natural gas uneconomic, which could have an adverse effect on our results of operations financial condition and cash flows.

Competition

Our gas gathering and marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

Regulation

The transportation and sale of natural gas and oil are heavily regulated. Interstate pipelines must obtain authorization from the FERC, to operate in interstate commerce, and state governments typically must authorize the construction of pipelines for intrastate service. The FERC currently allows interstate pipelines to adopt market-based rates; however, in the past the FERC has regulated pipeline tariffs and could do so again in the future. State tariff regulations vary. Currently, all our pipelines are intrastate.

State and local permitting, zoning and land use regulations can affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services to our midstream business may require licensing.

The transportation of natural gas and oil is also subject to extensive environmental regulation. We refer you to Other Environmental Regulation in Item 1 of Part I of this Annual Report and the risk factor We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Other

Our other operations have primarily consisted of real estate development activities. In 2013, we started construction on a corporate office complex located in Spring, Texas on 26 acres of commercial land that we purchased in 2012. The Company financed the construction of this complex through a construction agreement and lease arrangement. As of December 31, 2014, we were obligated for the construction costs incurred, which approximated $137 million. In January 2015, construction on the corporate office was completed and the Company commenced a lease with a term of approximately five years.

During 2012, we sold our office complex in Fayetteville, Arkansas and our interest in approximately 9.5 acres of real estate near the Fayetteville complex. In 2012, we also sold our office complex in Conway, Arkansas for approximately $32 million and subsequently leased back our Conway complex from the buyer for a 15-year term. There were no sales of commercial real estate in 2014 or 2013.

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Environmental Regulation

General. Our operations are subject to environmental regulation in the jurisdictions in which we operate. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements to drill or operate wells and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the natural gas and oil industry in general. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The following is a summary of the more significant existing environmental and worker health and safety laws and regulations to which we are subject.

Certain U.S. Statutes. CERCLA, also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy. However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as hazardous wastes, which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Clean Water Act, as amended, or CWA, and analogous state laws, impose restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to regulated waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

The Oil Pollution Act, as amended, or the OPA, and regulations thereunder impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. Although liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

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In 2014, 2013 and 2012, oil accounted for less than 1% of our total production, although we expect this percentage to increase as we develop our Southwest Appalachia assets.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed on them may be subject to CERCLA, the Clean Water Act, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

The Clean Air Act, as amended, restricts emissions into the atmosphere. Various activities in our operations, such as drilling, pumping and the use of vehicles, can release matter subject to regulation. We must obtain permits, typically from local authorities, to conduct various activities. Federal and state governmental agencies are looking into the issues associated with methane and other emissions from oil and natural gas activities, and further regulation could increase our costs or restrict our ability to produce. Although methane emissions are not currently regulated at the federal level, we are required to report emissions of various greenhouse gases, including methane.

Hydraulic Fracturing. We utilize hydraulic fracturing in drilling wells as a means of maximizing their productivity. It is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense and deep rock formations. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale and Northeast Appalachia are being utilized in our other operating areas, including Southwest Appalachia, the Sand Wash Basin and our Lower Smackover Brown Dense acreage and, in the future, may include our exploration program in New Brunswick, Canada. Successful hydraulic fracturing techniques are also expected to be critical to the development of other New Venture areas. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. In the Fayetteville Shale and Northeast Appalachia, the fracturing fluids we use are comprised of approximately 99.9% water and sand on a percentage volume basis. The remaining 0.1% is comprised of small quantities of additives which contain chemical compounds such as hydrochloric acid, phosphoric acid, glutaraldehyde and sodium chloride.

In the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing practice, both in the United States and abroad. In the United States, hydraulic fracturing is typically regulated by state oil and natural gas commissions, but there have recently been a number of regulatory initiatives at the federal and local levels as well as by other state agencies. New York State currently has a moratorium on hydraulic fracturing, and some local governments in the United States also ban this procedure. We currently do not have material properties in these areas. The newly elected provincial government in New Brunswick recently announced an intent to impose a moratorium on hydraulic fracturing until a list of conditions is met and has introduced authorizing legislation in the provincial legislature. We have applied for an extension of our licenses past the end of the moratorium, but as of this time that extension has not been granted. The list of conditions that the provincial government has announced is subjective, and we cannot predict the duration of the moratorium or whether we will be granted the extension requested or any other extension. Unless and until the moratorium is lifted and our licenses are extended, we will not be able to continue with our program in New Brunswick.

For example, the Environmental Protection Agency, or EPA, issued final rules effective as of October 15, 2012 that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the

New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS programs. The EPA final rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion, or REC techniques developed in the EPA's Natural Gas STAR program. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the final regulations under NESHAPS include maximum achievable control technology, or MACT, standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Based on our current operations and practices, management believes, such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management s view may change in the future.

In October 2011, the EPA also announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works or POTWs. The regulations will be developed

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under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. The EPA anticipates issuing the proposed rules in 2015.

In addition to the EPA, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A final draft of the report is expected for peer review and public comment in 2015. The U.S. Department of the Interior also is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Some states in which we operate have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We refer you to the risk factor Our financial condition and results of operation could be adversely affected by legislative and regulatory initiatives in the United States and elsewhere relating to environmental matters, particularly hydraulic fracturing and climate change, which could result in increased costs and additional operating restrictions or delays or prevent us from realizing the value of undeveloped acreage in Item 1A of Part I of this Annual Report.

Employee health and safety. Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (OSHA) and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Canada. Our activities in Canada have, to date, been limited to certain geological and geophysical activities that are not subject to extensive environmental regulation. If and when we begin drilling and development activities in New Brunswick, we will be subject to federal, provincial and local environmental regulations that we believe require compliance efforts comparable to those required in the United States.

Employees

As of December 31, 2014, we had 2,781 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2014. We believe that our relationships with our employees are good. In 2014, we were named a Top Workplace by the Houston Chronicle for the fifth consecutive year.

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GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below apply to the indicated terms as used in this Annual Report. All natural gas reserves and production reported in this Annual Report are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit. All currency amounts are in U.S. dollars unless specified otherwise.

Acquisition of properties   Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers   fees, recording fees, legal costs, and other costs incurred in acquiring properties. For additional information, see the SEC   s definition in Rule 4-10(a) (1) of Regulation S-X, a link for which is available at the SEC   s website.

Adjusted EBITDA   Net income (loss) plus interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties or (gain) loss on derivatives, net of settlement. We refer you to Management   s Discussion and Analysis of Financial Condition and Results of Operations   Results of Operations Reconciliation of Non-GAAP Measures   in Item 7 of Part II of this Annual Report for a table that reconciles Adjusted EBITDA with our net income (loss) from our audited financial statements.

Analogous reservoir   Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an   analogous reservoir   refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

For additional information, see the SEC   s definition in Rule 4-10(a) (2) of Regulation S-X, a link for which is available at the SEC   s website.

Available reserves   Estimates of the amounts of oil and natural gas which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis. For additional information, see the SEC   s definition in Item 1207(d) of Regulation S-K, a link for which is available at the SEC's website.

Bbl   One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf   One billion cubic feet of natural gas.

Bcfe   One billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of oil to six Mcf of natural gas.

Btu   One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Dekatherm   One million British thermal units (Btus).

Deterministic estimate The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure. For additional information, see the SEC s definition in Rule 4-10(a) (5) of Regulation S-X, a link for which is available at the SEC s website.

Developed oil and gas reserves Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For additional information, see the SEC s definition in Rule 4-10(a) (6) of Regulation S-X, a link for which is available at the SEC s website.

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Development costs   Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

For additional information, see the SEC s definition in Rule 4-10(a) (7) of Regulation S-X, a link for which is available at the SEC s website.

Development project   A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project. For additional information, see the SEC s definition in Rule 4-10(a) (8) of Regulation S-X, a link for which is available at the SEC s website.

Development well   A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. For additional information, see the SEC s definition in Rule 4-10(a) (9) of Regulation S-X, a link for which is available at the SEC s website.

Downspacing   The process of drilling additional wells within a defined producing area to increase recovery of natural gas and oil from a known reservoir.

E&P   Exploration for and production of natural gas and oil.

Economically producible   The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. For additional information, see the SEC s definition in Rule 4-10(a) (10) of Regulation S-X, a link for which is available at the SEC s website.

Estimated ultimate recovery (EUR)   Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date. For additional information, see the SEC s definition in Rule 4-10(a) (11) of Regulation S-X, a link for which is available at the SEC s website.

Exploitation   The development of a reservoir to extract its gas and/or oil.

Exploratory well   An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section. For additional information, see the SEC s definition in Rule 4-10(a) (13) of Regulation S-X, a link for which is available at the SEC s website.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc. For additional information, see the SEC s definition in Rule 4-10(a) (15) of Regulation S-X, a link for which is available at the SEC s website.

Fracture stimulation A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

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Gross well or acre A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. For additional information, see the SEC's definition in Item 1208(c)(1) of Regulation S-K, a link for which is available at the SEC's website.

Gross working interest Gross working interest is the working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest.

Infill drilling Drilling wells in between established producing wells to increase recovery of natural gas and oil from a known reservoir.

MBbls One thousand barrels of oil or other liquid hydrocarbons.

Mcf One thousand cubic feet of natural gas.

Mcfe One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

MMBbls One million barrels of oil or other liquid hydrocarbons.

MMBtu One million British thermal units (Btus).

MMcf One million cubic feet of natural gas.

MMcfe One million cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

Net revenue interest Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

Net well or Net acre The number of net wells or acres is the sum of the fractional working interests owned in individual wells or tracts. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website.

NGL Natural gas liquids.

NYMEX The New York Mercantile Exchange.

Operating interest An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

Overriding royalty interest A fractional, undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or natural gas well, that overrides a working interest.

Play A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

Present Value Index or PVI A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting or expecting to result from the investment by the dollars invested.

Probabilistic estimate The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence. For additional information, see the SEC s definition in Rule 4-10(a) (19) of Regulation S-X, a link for which is available at the SEC s website.

Producing property A natural gas and oil property with existing production.

Productive wells Producing wells and wells mechanically capable of production. For additional information, see the SEC's definition in Item 1208(c)(3) of Regulation S-K, a link for which is available at the SEC s website.

Proppant Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

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Proved developed producing Proved developed reserves that can be expected to be recovered from a reservoir that is currently producing through existing wells.

Proved developed reserves Proved gas and oil that are also developed gas and oil reserves.

Proved oil and gas reserves Proved oil and gas reserves are those quantities of oil and 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 prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Also referred to as proved reserves. For additional information, see the SEC s definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC s website.

Proved reserves See proved oil and gas reserves.

Proved undeveloped reserves Proved oil and gas reserves that are also undeveloped oil and gas reserves.

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 and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as present value. After-tax PV-10 is also referred to as standardized measure and is net of future income tax expense.

Reserve life index The quotient resulting from dividing total reserves by annual production and typically expressed in years.

Reserve replacement ratio The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.

Reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. For additional information, see the SEC s definition in Rule 4-10(a) (27) of Regulation S-X, a link for which is available at the SEC s website.

Royalty interest An interest in a natural gas and oil property entitling the owner to a share of oil or natural gas production free of production costs.

Tcf One trillion cubic feet of natural gas.

Tcfe One trillion cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

Unconventional play A play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds, or (3) shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

Undeveloped acreage Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. For additional information, see the SEC's definition in Item 1208(c)(4) of Regulation S-K, a link for which is available at the SEC's website.

Undeveloped oil and natural gas reserves Undeveloped oil and natural gas reserves are reserves of any category 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. Also referred to as undeveloped reserves. For additional information, see the SEC s definition in Rule 4-10(a) (31) of Regulation S-X, a link for which is available at the SEC s website.

Undeveloped reserves See undeveloped oil and natural gas reserves.

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USD United States Dollar.

Well spacing The regulation of the number and location of wells over an oil or natural gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission in the applicable jurisdiction. The order may be statewide in its application (subject to change for local conditions) or it may be entered for each field after its discovery. In the operational context, well spacing refers to the area attributable between producing wells within the scope of what is permitted under a regulatory order.

Working interest An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

Workovers Operations on a producing well to restore or increase production.

WTI West Texas Intermediate, the benchmark oil price in the United States.

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ITEM 1A. RISK FACTORS

In addition to the other information included in this Annual Report, the following risk factors should be considered in evaluating our business and future prospects. The risk factors described below represent what we believe are the most significant risk factors with respect to us and our business. In assessing the risks relating to our business, investors should also read the other information included in this Annual Report, including our financial statements and the related notes and Management s Discussion and Analysis of Financial Condition and Results of Operation Cautionary Statement about Forward-Looking Statements.

Our revenues and the value of our assets are highly dependent on the prices for natural gas and, to a lesser extent, oil. These prices are volatile, and a substantial or extended decline in natural gas and oil prices would have a material adverse effect on us.

Our financial results and the value of our assets correlate closely to the prices we can and do obtain for what we produce, in particular natural gas, which historically has accounted for almost 100% of our production. Prices for natural gas and oil are highly volatile and unpredictable. The following factors, among others, affect the supply of and demand for natural gas and oil:

- Changes in consumption patterns, including those resulting from population changes and migrations, new technologies and grown in emerging markets
- Global and local economic conditions
- Inventory levels
- Ability and cost of transporting product to markets, including the ability to connect resources to pipelines or other means of transportation, bottlenecks in pipeline or other transportation capacity such as many are experiencing in the Marcellus and the Utica Shales, export and import controls and other constraints
- Production disruptions
- Actions of governments and multinational groups, such as the Organization of Petroleum Exporting Countries (OPEC)
- Currency exchange rates
- Competition from other producers and from other energy sources, including renewables, which affects the level of supply
- Technological developments
- Weather, earthquakes and other natural events
- Market perceptions of future prices, whether due to the foregoing factors or others

A significant or extended decline in natural gas and oil prices, such as the one from 2008 into 2012 when the NYMEX natural gas price dropped from $13.58 to $1.91 per MMBtu, would have a material adverse effect on our financial position, our results of operations, our access to capital and the quantities of natural gas and oil that we can produce economically, including the following:

- The cash flows from our operations would be reduced, decreasing funds available for capital investments employed to replace reserves or increase production.
- Lower prices would reduce the value of our natural gas and oil assets and, in some cases, make them no longer be economic to produce. This could result in impairments to the values of our assets, such as occurred in 2012.
- Access to other sources of capital, such as equity or debt markets, could be severely limited or unavailable.
- We could fail to meet financial or other covenants in the documentation governing our debt, leading to mandatory prepayments or defaults.
- Locational price differentials change, making it difficult to predict the best locations to conduct our activities.
- Varying perceptions of future prices can lead to difficulties in agreeing on the value of assets in acquisitions or dispositions.

We endeavor to mitigate against these risks through hedging a significant portion of our production. Hedging also presents risks, including our failure to project the appropriate volumes and price points for hedges and the creditworthiness of our counterparties. For a discussion of our hedging activities, we refer you to Note 5 to the consolidated financial statements included in this Annual Report. Additionally, we mitigate these risks, in part, through our Midstream Services business, which generates cash flow that is largely fee-based and thus not directly impacted by commodity price volatility.

Our ability to sell our natural gas and oil and/or to receive market prices for our production may be adversely affected by constraints or interruptions on gathering systems, pipelines, processing and transportation systems owned or operated by us or others.

The marketability of our natural gas and oil production depends in part on the availability, proximity, and capacity of gathering systems, processing and pipeline and other transportation systems owned or operated by third parties. The lack of available capacity in these systems and facilities can result in shutting in producing wells, delaying or discontinuing the development plans for our properties or receiving lower prices. Although we have some contractual control over the transportation and gathering of our production, material changes in these business relationships could materially affect our operations. Federal and state regulation of natural gas and oil production, processing and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, and transport natural gas. In particular, continued development in the Appalachian Basin by us and others could overtax the capacity of existing gathering and pipeline system, and new or expanded capacity may not be in place in time.

The vast majority of our current operations and production are in the Fayetteville Shale, Northeast Appalachia and Southwest Appalachia, and significant events or circumstances affecting one or more of these areas could have a material and adverse effect on our operations in those areas and thus our overall performance.

Production from the Fayetteville Shale and Northeast Appalachia accounted for 64% and 33%, respectively, of our consolidated production and, when considering both our E&P and Midstream Services business, essentially all of our operating income in 2014. Our current Fayetteville Shale operations are almost entirely in Arkansas, and our current Northeast Appalachia and Southwest Appalachia operations currently are only in Pennsylvania and West Virginia. Significant events or circumstances of the types described elsewhere in these Risk Factors or otherwise that affect one or more of these areas would affect a very large part of our operations simultaneously and, even if they do not affect the industry generally, would affect us disproportionately compared to other companies. Those events and circumstances include changes in local laws and regulations, constraints on transportation, natural events, localized price changes and availability of water, skilled personnel, equipment, services and supplies, among others.

If we fail to find or acquire additional reserves, our reserves and production will decline materially from their current levels.

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Unless we acquire additional properties containing proved reserves, conduct successful exploration and development activities, successfully apply new technologies or identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future natural gas and oil production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

Our business could be adversely affected by competition with other companies.

The natural gas and oil industry is highly competitive, and our business could be adversely affected by companies that are in a better competitive position. As an independent natural gas and oil company, we frequently compete for reserve acquisitions, exploration leases, licenses and concessions, marketing agreements, transportation, equipment and labor against companies with financial and other resources substantially larger than those we possess. Many of our competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating in some of our core areas for a much longer time than we have or have established strategic long-term positions in geographic regions in which we may seek new entry.

Natural gas and oil exploration and production is an inherently risky business with many uncertainties and potential liabilities. The results of our activities may not be what we project, and not all our liabilities and other exposures may be covered by insurance.

By its nature, exploring for and producing natural gas and oil involves substantial capital investment with no assurance of return, or returns at expected levels, and the risk of environmental and other liability. Among other things:

· Although we utilize sophisticated geological and geophysical tools to determine where to drill, these do not predict with certainty the presence of natural gas or oil or the rate at which they can be produced. Some wells will result in no production, production that does not cover costs or production at lower levels than expected.

- During drilling we can face difficulties in landing our wellbore in the desired zones, staying in the desired zones while drilling horizontally, penetrating rock formations, controlling well pressure, stimulating reservoirs through fracturing and cleaning the wellbore following fracturing and running casing the entire length of the wellbore. These circumstances can delay completion, increase costs and possibly lead to the abandonment of the particular location.
- When we acquire properties or businesses through acquisitions, including properties already producing, we may fail to assess correctly the potential of the properties, the costs of integration and development, matters affecting legal title and thus the right to drill and ownership of production, the liabilities that we assume as part of the acquisition and the risks associated with ownership, development and operation.
- Equipment can fail or not be available and pipelines can rupture.
- We can encounter well blowouts, cratering, explosions, pipeline failure, fires, brine or other fluids, drainage of production from neighboring properties and other hazards.
- Earthquakes and hurricanes, storms and other weather events can interfere with drilling activities and operations.
- Although we believe we maintain a robust health, safety and environmental program, incidents can occur, whether due to natural events, the actions of third parties or our own errors or oversights. Spills, injuries or other calamities can result in liability for our Company, damage to our properties and interruption of our operations.

We maintain insurance against many potential losses or liabilities arising from our operations in accordance with customary industry practices and in amounts that we believe to be prudent. Our insurance does not protect us against all operational risks; for example, we generally do not maintain business interruption insurance, and pollution and environmental risks generally are not fully insurable. These risks could give rise to significant costs not covered by insurance that could have a material adverse effect upon our financial results.

Our business strategy depends on executing extensive drilling programs and controlling costs to improve our overall return. Shortages of oilfield equipment, services, supplies, raw materials and qualified personnel could adversely affect our ability to implement our programs or to achieve our desired levels of costs.

We are engaged in large-scale programs to develop our assets, particularly in the Fayetteville Shale, Northeast Appalachia and Southwest Appalachia. We are achieving economies of scale through our sizeable operations in these two areas and, in some cases, vertical integration in certain oilfield services, such as drilling, sand mining and pressure control. We nonetheless compete with other companies for oilfield equipment, services, supplies, raw materials and qualified personnel. In particular, the demand for qualified and experienced field personnel to drill wells and conduct field operations and for 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. These factors also cause significant increases in costs for equipment, services, personnel and raw materials (such as sand, cement, manufactured proppants and other materials utilized in the provision of the oilfield services). Higher natural gas and oil prices generally stimulate increased demand and result in increased costs for professional personnel, drilling rigs, crews and associated supplies, equipment, services and raw materials. In addition, our E&P operations also require local access to large quantities of water supplies and disposal services for produced water in connection with our hydraulic fracture stimulations due to prohibitive transportation costs. We cannot be certain when we will experience shortages or cost increases, which could adversely affect our profit margin, cash flow and operating results or restrict our ability to drill wells and conduct ordinary operations.

Our announced drilling plans can change due to various factors.

As of December 31, 2014, we had drilled and completed 3,742 operated wells relating to our Fayetteville Shale play and 277 operated wells relating to Northeast Appalachia. At year-end 2014, after the exclusion of our acreage in the traditional Fairway and the approximately 158,000 net federal acres we hold in the Ozark Highlands Unit, approximately 85% of our leasehold acreage in the Fayetteville Shale was held by production. Approximately 23%

and 54% of our leasehold acreage in Northeast Appalachia and Southwest Appalachia was held by production at year-end 2014, respectively. Our drilling plans are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful wells in addition to the natural gas and oil commodity price environment. The determination as to whether we continue to drill wells in our operating areas may depend on any one or more of the following factors:

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- our ability to determine the most effective and economic fracture stimulation;
- our ability to transport our production to the most favorable markets;
- material changes in natural gas prices (including regional basis differentials);
- changes in the costs to drill, complete or operate wells and our ability to reduce drilling risks;
- the extent of our success in drilling and completing horizontal wells;
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment services
- success or failure of wells drilled in similar formations of which would use the same production facilities;
- receipt of additional seismic or other geologic data or reprocessing of existing data;
- the extent to which we are able to effectively operate our own drilling rigs;
- availability and cost of capital; or
- the impact of federal, state and local government regulation, including any increase in severance taxes.

We continue to gather data about our prospects in our operating areas, and it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all.

Our ability to produce natural gas and oil could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.