SOUTHWESTERN ENERGY CO
Form 10-K
February 25, 2016
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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, 2015
Commission file number 001-08246

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 $8,694,538,969 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2015 of $22.73. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 23, 2016, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 389,664,470.

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 17, 2016 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, 2015

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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, the Health, Safety, Environment and Corporate Responsibility and the Nominating and Governance Committees of our Board of Directors are available on our website, and, upon request, in print free of charge to any stockholder. Information on our website is not incorporated into this report.

We file periodic reports, current 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 natural gas and oil company with operations predominantly in the United States, engaged in exploration, development and production activities, including related natural gas gathering and marketing. Southwestern is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries. Southwestern’s common and preferred stock are listed and traded on the NYSE under the ticker symbols “SWN” and “SWNC”, respectively.

Southwestern, which was incorporated in Arkansas in 1929 and reincorporated in Delaware in 2006, has its executive offices located at 10000 Energy Drive, Spring, Texas 77389, and can be reached by phone at 832-796-1000. The Company also maintains offices in Conway, Arkansas; Tunkhannock, Pennsylvania; and Jane Lew, West Virginia.

Our Business Strategy

Our Company is 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. The key elements of our business strategy, along with how we are implementing them in the current low commodity price environment, are as follows:

- Maintain a Strong Balance Sheet and Liquidity to Enhance Long-Term Shareholder Value. We believe a strong balance sheet and liquidity position are important to long-term value creation and extremely valuable in challenging pricing environments, helping to preserve options and flexibility.
  - What We Are Doing Now. As commodity prices fell during 2015, we reduced our capital program by approximately $800 million from what we expected early in the year. We are also committed to investing within cash flow levels rather than increasing debt in this lower-price environment. Although we have opportunities that meet our investment threshold described below, we are currently not drilling new wells as we focus on decreasing our debt levels. If and when prices improve and sufficient cash flow is generated, we expect to increase our activity levels and pursue these opportunities. With respect to debt and maturities, early in 2015 we paid off $5.0 billion of bank debt with long-term notes and equity, and late in the year we increased our liquidity by $750 million by entering into a three-year term loan and utilized the proceeds to pay down our revolving credit facility. We continue to look at ways to reduce debt levels and extend maturities.
- Exercise Capital Discipline. We prepare an economic analysis for our drilling programs and other investments based upon the expected net present value added for each dollar to be invested, which we refer to as Present Value

Index, or PVI. We target creating an average of at least a 1.3 PVI in our projects using a 10% discount rate. Our actual PVI results are utilized to help determine the allocation of our future capital investments and are reflected in our management compensation. This disciplined investment approach governs our investment decisions at all times, including the current lower-price commodity market.

o What We Are Doing Now. We continuously reassess our price expectations used in calculating expected PVI to align with market conditions. The current price environment reduces the number of wells and other projects that meet our PVI threshold, but even at current prices, we have projects that we expect would generate 1.3 PVI or above. As discussed above, the timing of those projects depends on availability of capital.

· Maximizing Margins and Production Available for Sale. We concentrate our operations in large, scalable projects, such as our large positions in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale. We believe this allows us the economies of scale that drives efficiency and learning opportunities. These efficiencies and learnings help improve future well results and enhance the economics of our portfolio. They also allow us to continuously identify ways to lower costs in each asset in which we operate. We routinely review costs in detail and analyze processes implemented, materials used and vendor relationships to enhance our economics and cost structure.

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- o What We Are Doing Now. Cost control has been a differentiator for us in the past, and we believe our focus on costs gives us a competitive advantage as we move into the future. We have successfully renegotiated contracts, improved well results and implemented continuous process improvements in each of our operating areas, resulting in these differentiating cost savings.

Our predominant operations, which we refer to as Exploration and Production ("E&P"), are focused on the finding and development of natural gas and oil reserves. We are also focused on creating and capturing additional value through our natural gas gathering and marketing segment, 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 unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as "Northeast Appalachia"), our operations in West Virginia are also focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as "Southwest Appalachia") and our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. Collectively, our properties located in Pennsylvania and West Virginia are herein referred to as the "Appalachian Basin." 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." We have exploration and production activities ongoing in Colorado and Louisiana along with other areas in which we are currently exploring for new development opportunities. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas and provide oilfield products and services, principally serving our exploration and production operations.

Midstream Services – Through our affiliated midstream subsidiaries, we engage in natural gas gathering activities in Arkansas and Louisiana. These activities primarily support our E&P operations and generate revenue from fees associated with the gathering of natural gas. Our marketing activities capture opportunities that arise through the marketing and transportation of the natural gas, oil and NGLs produced in our E&P operations.

Historically, 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, (gain) loss on derivatives, excluding derivatives, settled, gain on sale of assets and certain one-time charges ("Adjusted EBITDA"), have been derived from our E&P business. However, in 2015, depressed commodity prices significantly decreased our E&P results. In 2015, our E&P business had an operating loss of $154 million, excluding non-cash impairments of natural gas and oil properties, and constituted 75% of our Adjusted EBITDA, had operating income of $1,013 million in 2014 and constituted 82% of our Adjusted EBITDA and had an operating income of $879 million in 2013 and constituted 81% of our Adjusted EBITDA. The remainder of our consolidated operating income and Adjusted EBITDA in each of these years was primarily 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).

Recent Developments

CEO Succession. In January 2016, Steve Mueller, Chief Executive Officer since 2009, announced his retirement. He will remain on the Board of Directors as Non-Executive Chairman through the annual shareholder meeting in May 2016. Bill Way, previously the President and Chief Operating Officer of the company, was named Chief Executive Officer to replace Mr. Mueller. Mr. Way retained his title of President and was appointed to the Board of Directors.

Workforce Reduction. In January 2016, as a result of lower anticipated drilling activity we announced a 40% workforce reduction of approximately 1,100 employees, which included a majority of employees in our oilfield services businesses. This reduction should be substantially complete by the end of the first quarter of 2016.

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Exploration and Production

Overview

Operations in our E&P segment are primarily in the Appalachian Basin and Fayetteville Shale assets. We also have conducted additional exploration and production activities in other basins targeting various formations as part of our New Ventures projects.

Our E&P segment recorded an operating loss of $7,104 million in 2015, operating income of $1,013 million in 2014, and operating income of $879 million in 2013. The operating loss in 2015 was primarily a result of $7.0 billion, or $4.3 billion net of taxes, non-cash impairments of natural gas and oil properties due to the fall in commodity prices. Operating income for 2014 increased $134 million compared to 2013 as a result of an increase in revenue of $403 million from higher production volumes, an increase in revenue of $55 million from increased realized prices, offset by an increase in operating costs and expenses of $324 million associated with the expansion of our operations and higher activity levels in Northeast Appalachia and the Fayetteville Shale. In May 2015, we divested of our East Texas and Arkoma properties, previously referred to as the Ark-La-Tex division.

Adjusted EBITDA from our E&P segment was $1.1 billion in 2015, compared to $1.9 billion in 2014 and $1.6 billion in 2013. Our Adjusted EBITDA decreased in 2015 as lower realized natural gas prices and increased total operating costs and expenses due to increased activity levels more than offset the revenue impacts of higher production volumes. Our Adjusted EBITDA increased in 2014 as higher realized natural 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 when our E&P activity levels support these activities. 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. In 2016 through February 23, these operations have largely been inactive and we expect lower activity in these areas in 2016 due to reduced drilling activity resulting from lower commodity prices.

Drilling Services

We have conducted drilling operations for a majority of our operated wells. As of December 31, 2015, we had 13 re-entry rigs and 2 spudder rigs which were located in Pennsylvania, West Virginia, and Arkansas. In 2015, we provided drilling services for 82, 41 and 230 wells that we operate in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale, respectively, and were able to reduce our drilling costs on average by 1%, 2% and 1% per well for the wells we drilled in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale, respectively.

Hydraulic Fracturing

We provide pressure pumping services for a portion of our operated wells. As of December 31, 2015, 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 2015, we provided pressure pumping services for 192 wells that we operated in the Fayetteville Shale and were able to reduce our well completion costs on average by 6% per well for the wells we completed.

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, 2015, our sand mine is comprised of 570 acres and produces 30/70 and 100 mesh sized sand. In 2015, we provided sand for the completion of 261 wells operated by us in the Fayetteville Shale and were able to reduce our well completion costs on average by 11% per well for the wells for which we provided sand.

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Our Proved Reserves

Our estimated proved natural gas and oil reserves were 6,215 Bcfe at year-end 2015, compared to 10,747 Bcfe at year-end 2014 and 6,976 Bcfe at year-end 2013. The significant decrease in our reserves in 2015 was primarily due to downward price revisions in our proved undeveloped reserves associated with decreased commodity prices, partially offset by upward performance revisions in Northeast Appalachia and Southwest Appalachia and our successful development programs in the Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale. 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 Northeast Appalachia and the Fayetteville Shale 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, 2015, we utilized average prices from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.59 per MMBtu for natural gas, West Texas Intermediate oil of $46.79 per barrel for oil and $6.82 per barrel for NGLs compared to $4.35 per MMBtu for natural gas, $91.48 per barrel for oil and $23.79 per barrel for NGLs at December 31, 2014 and $3.67 per MMBtu for natural gas, $93.42 per barrel for oil and $43.45 per barrel for NGLs at December 31, 2013.

Our after-tax PV-10 was $2.4 billion at year-end 2015, $7.5 billion at year-end 2014, and $3.7 billion at year-end 2013. The decrease in our after-tax PV-10 value in 2015 compared to 2014 was primarily due to lower average natural gas, oil and NGL prices. The increase in our after-tax PV-10 value in 2014 over 2013 was primarily due to an 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 2015 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 2015 after-tax PV-10 computation does not have future income taxes because our tax basis in the associated oil and gas properties exceeded expected pre-tax cash inflows. Our year-end 2015 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $2.4 billion, compared to $9.5 billion at year-end 2014 and $5.1 billion at year-end 2013.

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, oil and NGL reserves, to the risk factor "Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" 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 2015, 95% of our estimated proved reserves were natural gas and 93% of total estimated proved reserves were classified as proved developed, compared to 91% and 55%, respectively, in 2014 and 100% and 61%, respectively in 2013. We operate, or if operations have not commenced, plan to operate, approximately 98% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index approximated 6.4 years at year-end 2015. In 2015, natural gas sales accounted for 93% of total operating revenues, compared to nearly 100% in 2014 and 2013.

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The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of fiscal year-end 2015 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2015 and sets forth 2015 annual information related to production and capital investments for each of our operating areas:

2015 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Appalachia				
	Northeast	Southwest	Fayetteville Shale	Other (1)	Total
Estimated Proved Reserves:					
Natural Gas (Bcf):					
Developed (Bcf)	2,005	311	3,156	2	5,474
Undeveloped (Bcf)	314	4	125	–	443
	2,319	315	3,281	2	5,917
Crude Oil (MMBbls):					
Developed (MMBbls)	–	8.5	–	0.3	8.8
Undeveloped (MMBbls)	–	–	–	–	–
	–	8.5	–	0.3	8.8
Natural Gas Liquids (MMBbls):					
Developed (MMBbls)	–	40.9	–	–	40.9
Undeveloped (MMBbls)	–	–	–	–	–
	–	40.9	–	–	40.9
Total Proved Reserves (Bcfe)(2):					
Developed (Bcfe)	2,005	607	3,156	4	5,772
Undeveloped (Bcfe)	314	4	125	–	443
	2,319	611	3,281	4	6,215
Percent of Total	37%	10%	53%	0%	100%
Percent Proved Developed	86%	99%	96%	100%	93%
Percent Proved Undeveloped	14%	1%	4%	0%	7%
Production (Bcfe)	360	143	465	8	976
Capital Investments (millions)(3)	$ 710	$ 857	$ 565	$ 105	$ 2,237
Total Gross Producing Wells(4)	774	1,085	4,268	20	6,147
Total Net Producing Wells(4)	407	859	2,971	17	4,254
Total Net Acreage	270,335 (5)	425,098 (6)	957,641 (7)	3,673,853 (8)	5,326,927
Net Undeveloped Acreage	168,753 (5)	193,582 (6)	288,569 (7)	3,661,375 (8)	4,312,279

PV-10:					
Pre-Tax (millions)(9)	$ 707	$ 115	$ 1,604	$ (9)	$ 2,417
PV of Taxes (millions)(9)	–	–	–	–	–
After-Tax (millions)(9)	$ 707	$ 115	$ 1,604	$ (9)	$ 2,417
Percent of Total	29%	5%	66%	0%	100%
Percent Operated(10)	98%	95%	99%	100%	98%

(1) Other includes New Ventures and the production from our Ark-La-Tex properties divested in May 2015.

(2) 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.

(3) Our Total and Fayetteville Shale capital investments exclude $21 million related to our drilling rig related equipment, sand facility and other equipment.

(4) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2015.

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(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 30,172 net acres in 2016, 57,724 net acres in 2017 and 12,891 net acres in 2018.

(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 36,934 net acres in 2016, 42,034 net acres in 2017 and 12,604 net acres in 2018. Of this acreage, 16,160 net acres in 2016, 15,262 net acres in 2017 and 1,990 net acres in 2018 can be extended for an average of an additional 4.8 years.

(7) The Fayetteville Shale acreage includes 31,413 net undeveloped acres and 170,743 net developed acres in the Arkoma Basin that have previously been reported as a component of our conventional Arkoma acreage. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 164 net acres in 2016, 453 net acres in 2017 and 31 net acres in 2018 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(8) 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 255,527 net acres in 2016, 217,927 net acres in 2017 and 23,086 net acres in 2018. With regard to our acreage in New Brunswick, Canada, exploration licenses were extended through 2021. With regard to our acreage in the Lower Smackover Brown Dense, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 58,849 net acres in 2016, 68,790 net acres in 2017 and 67,528 net acres in 2018. 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 85,767 net acres in 2016, 35,883 net acres in 2017, and 55,918 net acres in 2018.

(9) 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, oil and NGL reserves.

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

We refer you to Note 4 to our consolidated financial statements for a more detailed discussion of our proved natural gas, oil and NGL reserves as well as our standardized measure of discounted future net cash flows related to our proved natural gas, oil and NGL reserves. We also refer you to the risk factor "Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" 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 2013, 2014 and 2015.

CHANGES IN PROVED UNDEVELOPED RESERVES (BCFE)

	Appalachia				
	Northeast	Southwest	Fayetteville Shale	Other (1)	Total
December 31, 2012	442	–	364	15	821
Extensions, discoveries and other additions (2)	810	–	1,530	–	2,340
Total revision attributable to performance and production	(33)	–	(115)	(9)	(157)
Price revisions	26	–	18	1	45
Developed	(170)	–	(142)	–	(312)
Disposition of reserves in place	–	–	–	–	–
Acquisition of reserves in place	–	–	–	–	–
December 31, 2013	1,075	–	1,655	7	2,737
Extensions, discoveries and other additions (3)	589	–	573	–	1,162
Total revision attributable to performance and production (4)	307	–	(130)	(6)	171
Price revisions	11	–	24	–	35
Developed	(384)	–	(406)	–	(790)
Disposition of reserves in place	–	–	–	–	–
Acquisition of reserves in place (5)	–	1,481	–	–	1,481
December 31, 2014	1,598	1,481	1,716	1	4,796
Extensions, discoveries and other additions	138	4	34	–	176
Total revision attributable to performance and production	513	158	62	–	733
Price revisions	(1,447)	(1,413)	(1,357)	–	(4,217)
Developed	(488)	(226)	(330)	–	(1,044)
Disposition of reserves in place	–	–	–	(1)	(1)
Acquisition of reserves in place	–	–	–	–	–
December 31, 2015	314	4	125	–	443

(1) Other includes New Ventures and Ark-La-Tex properties divested in May 2015.
(2) The 2013 proved undeveloped reserve additions are primarily associated with the increase in gas prices.
(3) Primarily associated with the undeveloped locations that were added throughout the year in 2014 due to our successful drilling program.

(4) Primarily due to changes associated with the analysis of updated data collected in the year and decreases related to current year production.
(5) Our acquisition of reserves in place is attributable to the purchase of undeveloped locations in West Virginia and southwest Pennsylvania.

As of December 31, 2015, we had 443 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 2015, we invested $869 million in connection with converting 1,044 Bcfe, or 22%, of our proved undeveloped reserves as of December 31, 2014 into proved developed reserves and added 176 Bcfe of proved undeveloped reserve additions in the Appalachian Basin and the Fayetteville Shale. As a result of the depressed commodity price environment in 2015, we had downward price revisions of 4,217 Bcfe which were slightly offset by a 733 Bcfe increase due to performance revisions. As of December 31, 2014, we had 4,796 Bcfe of proved undeveloped reserves. 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 Appalachian Basin and the Fayetteville Shale. Our December 31, 2015 proved reserves include 217 Bcfe of proved undeveloped reserves from 75 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 $34 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves within the next five years.

We expect that the development costs for our proved undeveloped reserves of 443 Bcfe as of December 31, 2015 will require us to invest an additional $235 million 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. The decreased commodity price environment has resulted, and could continue to 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 "Natural gas, oil and natural gas liquids prices greatly affect our revenues, profitability, liquidity and growth and the value of our assets," "Significant capital expenditures are required to replace our reserves and conduct our business," and "Lower commodity prices may impair our ability to service our existing debt or refinance it when it becomes due" 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 2015, our reserve replacement ratio was negatively affected by net downward revisions of 4,083 Bcfe primarily as a result of the depressed commodity price environment. Excluding reserve revisions, we replaced 72% of our production volumes with 592 Bcfe of proved reserve additions and 114 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 416 Bcfe were proved developed and 176 Bcfe were proved undeveloped. In 2015, downward reserve revisions resulting from lower natural gas, oil and NGL prices totaled 2,315 Bcf, 1,875 Bcfe, 1,496 Bcf and 32 Bcfe in our Northeast Appalachia, Southwest Appalachia, Fayetteville Shale and other divisions, respectively. We also had upward performance revisions in 2015 of 1,383 Bcf, 209 Bcfe, 10 Bcf and 33 Bcfe in our Northeast Appalachia, Southwest Appalachia, Fayetteville Shale and other divisions, respectively. Additionally, our reserves decreased by 179 Bcfe as a result of our sale of natural gas and oil leases and wells in 2015.

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. Our reserve replacement ratio, excluding reserve revisions, was 520% in 2014.

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. Our reserve replacement ratio, excluding reserve revisions, was 501% in 2013.

For the period ended December 31, 2015, our three-year average reserve replacement ratio, including revisions and acquisitions, was 199%. Excluding reserve revisions and acquisitions, our three-year average reserve replacement ratio was 232%.

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 as a result of increased development activity, totaling 419 Bcf, 836 Bcf and 1,200 Bcf in 2015, 2014 and 2013, respectively. Additionally, we added 123 Bcfe of reserves in 2015 as a result of our drilling program in Southwest Appalachia, which was acquired in December 2014. We expect our drilling programs in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale 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 “Significant capital expenditures are required to replace our reserves and conduct our business” and “If we are not able to

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replace reserves, we may not be able to grow or sustain production.” 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

Northeast Appalachia

We began leasing acreage in northeast Pennsylvania in 2007 in an effort to participate in the emerging Marcellus Shale. As of December 31, 2015, we had approximately 270,335 net acres in Northeast Appalachia under which we believe the Marcellus Shale is present (168,753 net undeveloped acres and 101,582 net developed acres held by production), compared to approximately 266,073 net acres at year-end 2014 and 292,446 net acres at year-end 2013. Our undeveloped acreage position as of December 31, 2015 had an average royalty interest of 15% and was obtained at an average cost of approximately $990 per acre.

As of December, 31, 2015, we had spud or acquired 553 operated wells, 424 of which were on production and 542 of which are horizontal wells. In 2015, we invested approximately $710 million in Northeast Appalachia and spud 89 operated horizontal wells and acquired 86 horizontal and 2 vertical wells. Our reserves in Northeast Appalachia decreased by 873 Bcf in 2015, which included reserve additions of 340 Bcf, 1,383 Bcf of net upward revisions due to well performance, net downward price revisions of 2,315 Bcf and acquisitions of 79 Bcf, offset by production of 360 Bcf. Of the 89 horizontal wells spud during 2015, 79 wells are located in Susquehanna County, 4 wells are located in Bradford County, 4 wells are located in Tioga County and the remaining 2 wells are located in Wyoming County. We also acquired 86 horizontal wells in 2015, nearly all of which were located in Susquehanna County. In 2015, our operated horizontal wells had an average completed well cost of $5.4 million per well, average horizontal lateral length of 5,403 feet and an average of 11 fracture stimulation stages. This compares to an average completed operated well cost of $6.1 million per well, average horizontal lateral length of 4,752 feet and an average of 15 fracture stimulation stages in 2014. In 2013, our average completed operated well cost was $7.0 million per well with an average horizontal lateral length of 4,982 feet and an average of 18 fracture stimulation stages. Included in our total capital investments in Northeast Appalachia during 2015 was approximately $472 million for drilling and completions, $172 million for acquisition of properties, and $66 million in facilities, capitalized costs and other expenses. In 2014, we invested approximately $695 million in Northeast Appalachia, spud 99 operated wells, and acquired 5 horizontal and 2 vertical wells, resulting in reserve additions and revisions of 1,483 Bcf. In 2013, we invested approximately $872 million in Northeast Appalachia and spud 108 operated wells, resulting in net reserve additions and revisions of 1,297 Bcf.

Approximately 2,319 Bcf of our total proved net reserves at year-end 2015 were attributable to Northeast Appalachia. We had a total of 423 horizontal and one vertical well that we operated and that were on production as of December 31, 2015, resulting in net production from this area of 360 Bcf in 2015, compared to 254 Bcf in 2014 and 151 Bcf in 2013. Our 2015 year-end reserves in Northeast Appalachia include a total of 826 locations, of which 767 were proved developed producing, 23 were proved developed non-producing and 36 were proved undeveloped. At year-end 2014, we had approximately 3,192 Bcf in proved reserves in Northeast Appalachia from 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 of proved reserves in Northeast Appalachia from a total of 522 locations, of which 333 were proved developed producing, and 189 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2015 was approximately 10.4 Bcf per well, compared to 9.6 Bcf per well at year-end 2014 and 6.9 Bcf per well in 2013.

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.

Southwest Appalachia

In late 2014 and early 2015, we closed two transactions to acquire natural gas and oil assets in West Virginia and southwest Pennsylvania for approximately $5.4 billion. This acreage has at least three drilling objectives, namely the Marcellus, Utica and Upper Devonian Shales. As of December 31, 2015, we had approximately 425,098 net acres in Southwest Appalachia (193,582 net undeveloped acres and 231,516 net developed acres held by production) compared to

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approximately 413,376 net acres at year-end 2014. Our undeveloped acreage position as of December 31, 2015 had an average royalty interest of 16%.

In 2015, we invested approximately $857 million in Southwest Appalachia, which included approximately $248 million to spud 48 wells. Net production from Southwest Appalachia was 143 Bcfe in 2015. Included in our total capital investments in Southwest Appalachia during 2015 was approximately $409 million for acquisition of properties and $200 million in capitalized costs and other expenses. Approximately 611 Bcfe of our total proved net reserves at year-end 2015 were in Southwest Appalachia and substantially all attributable to the Marcellus Shale. Our reserves in Southwest Appalachia decreased by 1,686 Bcfe in 2015, which included reserve additions of 88 Bcfe, 209 Bcfe of net upward revisions due to well performance, net downward price revisions of 1,875 Bcfe, and acquisitions of 35 Bcfe, offset by production of 143 Bcfe. We had a total of 318 horizontal and 676 vertical wells that we operated and that were on production as of December 31, 2015. Additionally, there were 43 horizontal wells in progress at the end of 2015, of which 21 were waiting on pipeline or production facilities. Our 2015 year-end reserves in Southwest Appalachia include a total of 1,429 locations, of which 1,028 were proved developed producing, 400 were proved developed non-producing and 1 was proved undeveloped. At December 31, 2014, approximately 2,297 Bcfe of total proved net reserves were attributable to Southwest Appalachia from 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.

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 Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Southwest Appalachia production.

Fayetteville Shale

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, 2015, we held leases for approximately 957,641 net acres in the play area (257,156 net undeveloped acres, 498,329 net developed acres held by Fayetteville Shale production, 170,743 net developed acres held by conventional production in the Arkoma Basin, and 31,413 net undeveloped acres in the Arkoma Basin), compared to approximately 888,161 net acres at year-end 2014 and 905,684 net acres at year-end 2013. Certain acreage previously reported as a component of our conventional Arkoma Basin has been included in the unconventional net acreage for the Fayetteville Shale at December 31, 2015, reflecting our current drilling focus.

Approximately 3,281 Bcf of our reserves at year-end 2015 were attributable to our Fayetteville Shale properties, compared to approximately 5,069 Bcf at year-end 2014 and 4,795 Bcf at year-end 2013. Our reserves in the Fayetteville Shale decreased by 1,788 Bcf in 2015, which included reserve additions of 163 Bcf, net downward price revisions of 1,496 Bcf, 10 Bcf of net upward revisions due to well performance, offset by production of 465 Bcf. Our net production from the Fayetteville Shale was 465 Bcf in 2015, compared to 494 Bcf in 2014 and 486 Bcf in 2013.

At year-end 2015, after excluding our acreage in the conventional Arkoma Basin and the federal acreage we hold in the Ozark Highlands Unit, approximately 87% of our 597,254 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 I of this Annual Report. Our acreage position was obtained at an average cost of approximately $335 per acre and has an average royalty interest of 15%. We refer you to the risk factor “Certain of our undeveloped assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage" 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 we are 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, 2015, we had spud a total of 4,737 wells in the Fayetteville Shale since our commencement of activities there in 2004, of which 4,157 were operated by us and 580 were outside-operated wells. Of these wells, 155 were spud in 2015, 468 in 2014 and 527 in 2013. All of the wells spud in 2015 were designated as horizontal wells. At year-end 2015, 4,003 wells operated by the Company had been drilled and completed overall, including 3,912 horizontal wells.

In 2015, the horizontal wells we drilled as operator had an average completed well cost of $2.8 million per well, average horizontal lateral length of 5,729 feet, and an average time to drill to total depth of 7.3 days from re-entry to re-entry. This compares to an average completed operated well cost of $2.6 million per well, average horizontal lateral length of 5,440 feet and average time to drill to total depth of 6.8 days from re-entry to re-entry during 2014. In 2013, our average completed operated well cost was $2.4 million per well with an 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. The operated wells we placed on production during 2015 averaged initial production rates of 4,280 Mcf per day, compared to average initial production rates of 4,430 Mcf per day in 2014 and 4,041 Mcf per day in 2013. During 2015, we placed 74 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, compared to 145 wells in 2014 and 93 wells in 2013.

Our total proved net reserves in the Fayetteville Shale at year-end 2015 were from a total of 4,560 locations, of which 4,268 were proved developed producing, 231 were proved developed non-producing and 61 were proved undeveloped. Of the 4,560 locations, 4,493 were horizontal. The average gross proved reserves for the undeveloped wells included at year-end 2015 was approximately 3.0 Bcf per well, compared to 2.3 Bcf per well at year-end 2014, and 2.5 Bcf per well at year-end 2013. The increase in average gross proved reserves for our undeveloped wells in 2015 was primarily due to the estimated ultimate recoveries of those locations which remained economic at the average prices utilized during 2015. 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. Total proved net natural gas reserves in the Fayetteville Shale in 2014 were approximately 5,069 Bcf 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. Total proved net natural gas reserves in the Fayetteville Shale in 2013 totaled 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.

In 2015, we invested approximately $565 million in the Fayetteville Shale, which included approximately $481 million to spud 155 wells, all of which we operate. Included in our total capital investments in the Fayetteville Shale during 2015 were $80 million in capitalized costs and other expenses and $4 million for acquisition of properties. In 2014, we invested approximately $944 million in the Fayetteville Shale, which included $838 million to spud 468 wells, 464 of which we operate, $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. As of December 31, 2015, 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.

New Ventures

We also 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, 2015, we held 3,661,375 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 4,170,687 net undeveloped acres held at year-end 2014 and 3,972,732 net undeveloped acres held at year-end 2013.

Activity on our New Ventures assets was limited in 2015 as a result of the low commodity price environment. We are currently in the process of marketing these assets and anticipate activity to remain limited in 2016 as we focus on more proven development plays. 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.

Sand Wash Basin. In 2014, we acquired acreage in northwest Colorado targeting crude oil, NGLs and natural gas contained in the Sand Wash Basin, with the target zone ranging in vertical depth from 5,500 to 11,500 feet. Our leases currently have an approximate 81% average net revenue interest. As of December 31, 2015, we held approximately 251,478 net acres in the area, obtained at an average cost of $570 per acre.

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, 2015, we held approximately 201,091 net acres in the area, obtained at an average cost of $1,313 per acre. Our leases currently have an approximate 80% average net revenue interest. As of December 31, 2015, we had drilled 14 operated wells in the area, 6 of which were currently producing. In 2015, we processed and analyzed 3-D seismic data and believe that we have a better understanding of factors contributing to the quality of the wells drilled 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. In 2015, the provincial government in New Brunswick announced a moratorium on hydraulic fracturing until a list of conditions is met. The list of conditions that the provincial government has announced is somewhat subjective, and although the provincial government has stated that it expects to make a decision on the moratorium by the end of 2016, we cannot predict whether or when it may be lifted. Unless and until the moratorium is lifted, we will not be able to continue with our program in New Brunswick. In response to this moratorium, the Company requested and was granted an extension of its licenses. With these extensions, our licenses are scheduled to expire in March 2021.

Acquisitions and Divestitures

In May 2015, the Company sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $211 million. As of December 2014, these assets included approximately 184 Bcf of proved reserves.

In April 2015, the Company sold its gathering assets located in Bradford and Lycoming counties in northeast Pennsylvania for approximately $489 million. The assets included approximately 100 miles of natural gas gathering pipelines, with nearly 600 million cubic feet per day of capacity.

In January 2015, we acquired approximately 46,700 net acres in northeast Pennsylvania for $270 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 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 $357 million.

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 2015, we invested a total of approximately $2.3 billion in our E&P business. In 2015, we placed 430 wells to sales and had 203 wells in progress. Of the 203 wells in progress at year-end, 83, 43 and 77 were located in our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale operating areas, respectively, and 41 of these wells are waiting on pipeline or production facilities. Of the approximately $2.3 billion invested in our E&P business in 2015, approximately $710 million was invested in Northeast Appalachia, $857 million in Southwest Appalachia, $565 million in the Fayetteville Shale, and $102 million in New Ventures projects.

Of the $2.3 billion invested in 2015, approximately $1.2 billion was invested in exploratory and development drilling and workovers, $607 million for acquisition of properties, $390 million in capitalized interest and other expenses and $6 million for seismic expenditures. Additionally, we invested approximately $21 million in our drilling rigs and related equipment, sand facility and other equipment, and $8 million in water facilities. In 2014, we invested approximately $7.3 billion in our primary E&P business activities and participated in drilling 576 wells. Of the $7.3 billion invested in 2014, approximately $5.3 billion was invested for acquisition of properties, $1.5 billion in exploratory and development drilling and workovers, $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 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.

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Based on current commodity prices, our capital program for 2016 will be flexible and aligned with expected cash flow. This will involve little, if any, drilling at current prices unless we realize additional cash. 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 2016.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 2,675 MMcfe in 2015, compared to 2,105 MMcfe in 2014 and 1,800 MMcfe in 2013. Total natural gas equivalent production was 976 Bcfe in 2015, up from 768 Bcfe in 2014 and 657 Bcfe in 2013. Our natural gas production was 899 Bcf in 2015, compared to 766 Bcf in 2014 and 656 Bcf in 2013. The increase in production in 2015 resulted primarily from a 106 Bcf increase in net production from our Northeast Appalachia properties and a 140 Bcfe increase in net production from our Southwest Appalachia properties, which more than offset a 29 Bcf decrease in net production from our Fayetteville Shale properties and a combined 9 Bcfe decrease in net production from our East Texas and Arkoma Basin properties, which were divested in the first half of 2015. 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. We produced 2,265 MBbls of oil in 2015, compared to 235 MBbls of oil in 2014 and 138 MBbls of oil in 2013. Our oil production has increased in 2015 and 2014 primarily due to the acquisition of natural gas and oil properties in Southwest Appalachia and our exploration activities in the Brown Dense. In 2015, we produced 10,702 MBbls of NGLs, compared to 231 MBbls and 50 MBbls of NGLs in 2014 and 2013, respectively, primarily due to the acquisition of natural gas and oil properties in Southwest Appalachia and our exploration activities in the Brown Dense.

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, 2015, we did not have any New York Mercantile Exchange, or NYMEX, commodity price hedges in place on our targeted 2016 natural gas production. As of February 23, 2016, we had NYMEX commodity price hedges in place on 37 Bcf of our targeted 2016 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 Part II of this Annual Report, "Quantitative and Qualitative Disclosures about Market Risks," for further information regarding our hedge position as of December 31, 2015.

Including the effect of hedges, we realized an average price of $2.37 per Mcf for our natural gas production in 2015, compared to $3.72 per Mcf in 2014 and $3.65 per Mcf in 2013. Our hedging activities increased our average realized natural gas sales price by $0.46 per Mcf in 2015, compared to a decrease of $0.02 per Mcf in 2014 and an increase of $0.48 per Mcf in 2013. Our average oil price realized was $33.25 per barrel in 2015, compared to $79.91 per barrel in 2014 and $103.32 per barrel in 2013. Our average realized NGL price was $6.80 per barrel in 2015, $15.72 per barrel in 2014 compared to $43.63 per barrel in 2013. None of our oil or NGL production was hedged during 2015, 2014 or 2013.

During 2015, the average price received for our natural gas production, excluding the impact of hedges, was approximately $0.75 per Mcf lower than average NYMEX prices. Differences between NYMEX and price realized are due primarily to locational differences and transportation cost. As of December 31, 2015, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 216 Bcf and 67 Bcf of our 2016 and 2017 production, respectively, and expected natural gas production through physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.16) per Mcf and ($0.20) per Mcf for 2016 and 2017, respectively. Additionally, we have financial hedges in place on 5 Bcf of our 2016 production at a weighted average basis differential of $0.75 per Mcf.

Delivery Commitments. As of December 31, 2015, we had natural gas delivery commitments of 455 Bcf in 2016 and 198 Bcf in 2017 under existing agreements. These amounts are well below our forecasted 2016 natural gas production from our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia divisions and anticipated 2017 production from our available reserves in our Fayetteville Shale, Northeast Appalachia and Southwest 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, 2015, 2014 and 2013, 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. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. We also face competition for pipeline and other services to transport our product 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. In December 2015, the federal government repealed a 40-year ban on the export of crude oil. The export of natural gas continues to require federal permits. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") and the rules that the U.S. Commodity Futures Trading Commission, or the CFTC, the SEC, and certain other regulators have issued thereunder regulate certain swaps, futures, and options contracts in the major energy markets, including for natural gas and oil.

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 are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" 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, oil and NGLs. Our gathering assets support our E&P operations and are currently concentrated in the Fayetteville Shale in Arkansas after the sale of our gathering assets in northeast Pennsylvania and Texas in the second quarter of 2015.

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Our operating income from this segment was $583 million on revenues of $3.1 billion in 2015, compared to $361 million on revenues of $4.4 billion in 2014 and $325 million on revenues of $3.3 billion in 2013. Operating income in 2015 includes a $277 million net gain related to the sale of our northeast Pennsylvania and East Texas gathering assets. Excluding this gain, operating income decreased to $306 million in 2015 primarily due to a decrease in volumes gathered resulting from lower production volumes in the Fayetteville Shale and the sale of our northeast Pennsylvania gathering assets. Revenues decreased in 2015 primarily due to the prices received for volumes marketed. Revenues increased in 2014 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 $368 million in 2015, compared to $418 million in 2014 and $377 million in 2013. The decrease in 2015 was primarily due to decreased gathered volumes. The increase in 2014 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). During the years ended December 31, 2015, 2014 and 2013, no single third-party customer in our Midstream Services Segment accounted for 10% or more of our consolidated revenues.

Gas Gathering

Currently, our gas gathering activities are located predominantly in Arkansas and are related to the operation of our Fayetteville Shale asset. We invested approximately $58 million related to our gathering activities in 2015 and had gathering revenues of $491 million, compared to $144 million invested and revenues of $562 million in 2014 and $158 million invested and revenues of $516 million in 2013. During 2015, we divested our gathering assets in northeast Pennsylvania and East Texas. The divested gathering assets accounted for $21 million, $67 million and $48 million of our gathering revenues for the years ended December 31, 2015, 2014 and 2013, respectively.

During 2015, we gathered approximately 750 Bcf of natural gas in the Fayetteville Shale area, including 55 Bcf of natural gas from third-party operated wells. During 2014, we gathered approximately 812 Bcf of natural gas volumes in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party operated wells. In 2013, we gathered approximately 790 Bcf of natural gas volumes in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party wells. At the end of 2015, we had approximately 2,044 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 502,555 horsepower had been installed at 58 central point gathering facilities in the Fayetteville Shale.

Marketing

We attempt to capture opportunities related to the marketing and transportation of natural gas, oil and NGLs; although, 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 2015, we marketed 1,127 Bcfe, compared to 904 Bcf in 2014 and 786 Bcf in 2013. Of the total gas volumes marketed, production from our affiliated E&P operations accounted for 97% in 2015, compared to 97% in 2014 and 96% in 2013. Our Midstream Services segment also marketed approximately 60% of our combined oil and NGL production for the year ended December 31, 2015.

Northeast Appalachia

In January 2015, we completed the purchase of certain natural gas and oil 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.

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 which is expected to be in service in the second half of 2017.

In May 2013, we entered into a precedent agreement with Columbia Gas Transmission, LLC for a project that expanded their existing system from Chester County, Pennsylvania to various interconnects throughout Pennsylvania, New Jersey, Maryland, and Virginia. Our volume on this project, which was placed in service October 2015, is 72,000 Mcf per day.

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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 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.

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 we have subscribed for approximately 100,000 Mcf 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.

Southwest Appalachia

As part of our December 2014 acquisition of natural gas and oil 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 December 2014, we also were assigned certain ethane transportation agreements that allow for the transport of our ethane production to both domestic and international markets.

In March 2015, we entered into a precedent agreement with Columbia Pipeline Group, Inc. that secured capacity of 500,000 Mcf per day on the Mountaineer XPress pipeline, with a portion of these volumes going to the Gulf Coast on the Gulf Xpress pipeline. The project is expected to be in service by late 2018 and will be routed through much of our core Southwest Appalachia acreage located in West Virginia.

At December 31, 2015, we had 450,000 Mcf per day of firm processing capacity with multiple processing providers located near our core acreage position in West Virginia. In the future, we have the option to increase our firm processing capacity by exercising options for the construction of incremental processing trains, the use of interruptible processing capacity, or consummating new processing agreements with new or existing service providers.

Fayetteville Shale

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 Mcf 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 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.

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Demand Charges

As of December 31, 2015, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $8.9 billion, 38% of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. We also have guarantee obligations of up to $960 million of that amount. Additionally, $100 million relates to demand charges under firm transportation agreements under which we have the option to reduce our commitment by 531 Bcf beginning in 2018.

We refer you to the risk factor “We have made significant investments in pipelines and gathering systems and contracts and in oilfield service businesses, including our drilling rig, pressure pumping equipment and sand mine operations, to lower costs and secure inputs for our operations and transportation for our production. If our exploration and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.”

Competition

Our 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 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 pipelines we own 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 are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities” 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. In January 2015, construction on the corporate office was completed and the Company commenced a lease with a term of approximately five years.

We sold no commercial real estate in 2015, 2014 or 2013.

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

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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 may result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements. We do not expect continued compliance with existing requirements to have a material adverse impact on us, but 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, legislative and regulatory initiatives have been considered 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 measures were to be enacted, it could have a significant impact on our operating costs. 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 regulated 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 regulated 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. In 2015, 2014 and 2013, 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.

The Endangered Species Act and comparable state laws protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying us from obtaining drilling and other permits and may include restrictions on road building and other activities in areas containing the affected species or their habitats. Based on the species that have been identified to date, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our operations at this time.

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 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 federal agencies have started to assert regulatory authority over certain aspects of the process. 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. In August 2015, the EPA released proposed additional regulations that would control methane and volatile organic compound emissions from certain oil and gas equipment and operations. The EPA also recently proposed pretreatment standards that would prohibit the indirect discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. Based on our current operations and practices, management believes, such newly promulgated and proposed 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 addition, 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 was released for peer review and public comment in 2015.

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. In 2015, the provincial government in New Brunswick announced a moratorium on hydraulic fracturing until a list of conditions is met. The list of conditions is subjective, and although the provincial government has stated that it expects to make a decision on the moratorium by the end of 2016, we cannot predict whether or when it may be lifted. Unless and until the moratorium is lifted, we will not be able to continue with our program in New Brunswick.

In addition, concerns have been raised about the potential for earthquakes to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. We operate injection wells and

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utilize injection wells owned by third parties to dispose of waste water associated with our operations. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others.

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 “We are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities” in Item 1A of Part I of this Annual Report.

Greenhouse Gas Emissions. In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet “best available control technology” standards that will be established on a case-by case basis. One of our subsidiaries operates compressor stations, which are facilities that are required to adhere to the PSD or Title V permit requirements. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. More recently, in 2015, the Obama Administration announced that the EPA is expected to finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025. EPA proposed such regulations in August 2015.

Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse effect on our business.

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.

Employees

As of December 31, 2015, we had 2,597 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2015. We believe that our relationships with our employees are good. In January 2016, as a result of lower anticipated drilling activity due to a prolonged depressed commodity price environment, we announced a workforce reduction of approximately 1,100 employees. We expect this reduction to be substantially complete by the end of the first quarter of 2016. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, amendments to outstanding equity awards to modify forfeiture provisions.

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 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, (gain) loss on derivatives, excluding derivatives, settled, gain on sale of assets and certain one-time charges. 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 natural gas, oil and NGLs 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.

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"Bcfe" One billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of oil or natural gas liquids 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.

"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.

"Development costs" Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing natural gas, oil and NGLs. 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.

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"Exploitation" The development of a reservoir to extract its natural 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.

"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.

"Mont Belvieu" A pricing point for North American NGLs.

"Net acres" The sum, for any area, of the products for each tract of the acres in that tract multiplied by the working interest in that tract. 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.

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

"Net well" The sum, for all wells being discussed, of the working interests in those wells. 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.

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"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.

"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 natural gas, oil and NGLs that are also developed natural gas, oil and NGL reserves.

"Proved oil and gas reserves" Proved natural gas, oil and NGL reserves are those quantities of natural gas, oil and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – 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 natural gas, oil and NGL reserves."

"Proved undeveloped reserves" Proved natural gas, oil and NGL reserves that are also undeveloped natural gas, oil and NGL reserves.

"PV-10" When used with respect to natural gas, oil and NGL 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 natural gas, oil or NGL 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 natural gas, oil and NGL reserves” Undeveloped natural gas, oil and NGL 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 natural gas, oil and NGL reserves."

"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

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

Natural gas, oil and natural gas liquids prices greatly affect our revenues, profitability, liquidity and growth and the value of our assets.

Our revenues, profitability, liquidity and growth and the value of our assets greatly depend upon prices for natural gas, oil and natural gas liquids. The markets for these commodities have been volatile, and we expect that volatility to continue. The prices of natural gas, oil and natural gas liquids fluctuate in response to changes in supply and demand (global, regional and local), transportation costs, market uncertainty and other factors that are beyond our control. Short- and long-term prices are subject to a myriad of factors such as:

- overall demand, including the relative cost of competing sources of energy or fuel;
- overall supply, including costs of production;
- the availability, proximity and capacity of pipelines, other transportation facilities and gathering, processing and storage facilities;
- regional basis differentials;
- national and worldwide economic and political conditions;
- weather conditions and seasonal trends;
- government regulations, such as regulation of natural gas transportation and price controls;
- inventory levels; and
- market perceptions of future prices, whether due to the foregoing factors or others.

For example, in 2015 and 2014, our production was approximately 92% and 100% natural gas, respectively, and during this period spot prices ranged from a high of $8.15 per Mcf in February 2014 to a low of $1.63 per Mcf in December 2015. These price changes are not predictable.

In our exploration and production business, lower natural gas, oil and natural gas liquids prices directly reduce our revenues and thus our operating income and cash flow. Lower prices also reduce the projected profitability of further drilling and therefore are likely to reduce our drilling activity, which in turn means we will have fewer wells on production in the future. See “Significant capital expenditures are required to replace our reserves and conduct our business.” Lower prices also reduce the value of our assets, both by a direct reduction in what the production would be worth and by making some properties uneconomic, resulting in impairments to the recorded value of our reserves and non-cash charges to earnings. For example, in 2015, we reported a non-cash impairment charge on our natural gas and oil properties of $7.0 billion, primarily resulting from a 41% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of December 31, 2015, as compared to December 31, 2014, and the impairment of certain undeveloped leasehold interests. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the first quarter of 2016 ranging from approximately $300 million to $500 million, net of tax, when excluding future changes in costs excluded from amortization, with likely material impairments continuing beyond the first quarter. Further impairments in subsequent periods will occur if the trailing 12-month commodity prices continue to fall as compared to the average used in prior periods.

In our Midstream Services segment, lower production by us and others can mean reduced volumes being transported in the gathering systems we operate and thus lower revenues.

The dramatic drop in prices in the past two years has reduced our revenues, profits and cash flow, caused us to record significant asset impairments and led us to reduce both our level of capital investing, which may result in lower production levels, and our workforce, which has caused us to incur significant expenses relating to terminations. Further price decreases could have similar consequences. Similarly, a rise in prices to levels experienced in 2013 and into the middle of 2014 could significantly increase our revenues, profits and cash flow, which could be used to expand capital investments and thus future production.

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Significant capital expenditures are required to replace our reserves and conduct our business.

Our exploration, development and acquisition activities require substantial capital expenditures. We intend to fund our capital expenditures through net cash flows from operations. Our ability to generate operating cash flow is subject to many of the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Future cash flows from operations are subject to a number of risks and variables, such as the level of production from existing wells, prices of natural gas, oil and natural gas liquids, our success in developing and producing new reserves and the other risk factors discussed herein. If we are unable to fund capital expenditures, we could experience a further curtailment of our exploration and production operations, a loss of properties and a decline in our natural gas, oil and natural gas liquids production and reserves. In particular, prices at the levels experienced in December 2015 and January 2016, should they continue, would not support any material new drilling or acquisitions.

If we are not able to replace reserves, we may not be able to grow or sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional natural gas, oil and NGL reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. In addition, approximately 7% of our total estimated proved reserves (by volume) as of December 31, 2015 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Thus, our future natural gas and oil reserves and production, and therefore our cash flow and income, are highly dependent on our level of capital investments, our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

A further downgrade in our credit rating could negatively impact our cost of and ability to access capital and our liquidity.

Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under further review for a downgrade, could affect the market value of our senior notes and increase our corporate borrowing costs, including the interest rates charged under our credit facility and term loan credit facility. Such ratings are limited in scope, and do not address all material risks relating to us, but rather reflect only the view of each rating agency at the time the rating is issued of the likelihood we will be able to repay our debt. An explanation of the significance of such rating may be obtained from such rating agency. As of February 23, we were rated B1 by Moody's, BB+ by Standard and Poor's and BBB- by Fitch Investor Services. There can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency's judgment, circumstances so warrant.

Actual downgrades in our credit ratings may also impact our liquidity. Many of our existing commercial contracts contain, and future commercial contracts may contain, provisions permitting the counterparty to require increased security upon the occurrence of a downgrade in our credit rating. Providing additional security, such as the posting of a letter of credit, could reduce our available cash or our liquidity under our revolving credit facility for other purposes. The amount of additional security would depend on the severity of the downgrade from the credit rating agencies, and a downgrade could result in a material decrease in our liquidity.

Lower commodity prices may impair our ability to service our existing debt or refinance it when it becomes due.

As of December 31, 2015, we had $4.7 billion of debt outstanding, consisting principally of $3.9 billion in long-term senior notes maturing in various increments from 2017 to 2025, $750 million in a term loan due in 2018 and $116 million under our revolving credit agreement, which also matures in 2018. At current commodity price levels, our net cash flow from operations is substantially higher than our interest obligations under this debt, but further significant drops in prices could affect our ability to pay our current obligations or refinance our debt as it becomes due.

Moreover, general industry conditions may make it difficult or costly to refinance increments of this debt as it matures. Our current credit agreements and indentures do not contain significant covenants restricting our operations and other activities, but future credit arrangements could impose such restrictions. Our inability to pay our current obligations or refinance our debt as it becomes due could have a material and adverse effect on our company.

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Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging in the face of shifting market conditions, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our future growth rate.

We necessarily must consider future price and cost environments when deciding how much capital we are likely to have available from net cash flow and how best to allocate it. Our current philosophy is to operate within net cash flow and to invest capital in projects only if they are projected to generate a PVI of 1.3 or greater. Volatility in prices and potential errors in estimating costs, reserves or timing of production of the reserves could result in uneconomic projects or economic projects generating less than 1.3 PVI.

Certain of our undeveloped assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

Leases on approximately 158,879 (including 158,231 net acres held on federal lands that are currently suspended by the Bureau of Land Management) net acres of our Fayetteville Shale acreage will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Approximately 100,787 and 91,572 net acres of our Northeast Appalachia and Southwest Appalachia acreage, respectively, will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Our ability to drill wells depends on a number of factors, including certain factors that are beyond our control, such as the ability to obtain permits on a timely basis or to compel landowners or lease holders on adjacent properties to cooperate. Further, we may not have sufficient capital to drill all the wells necessary to hold the acreage without increasing our debt levels. To the extent we do not drill the wells, our rights to acreage can be lost.

Natural gas and oil drilling and producing operations can be hazardous and may expose us to liabilities.

Exploration and production operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our prospects. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and

· injunctions resulting in limitation or suspension of operations.

For our non-operated properties, we are dependent on the operator for operational and regulatory compliance.

Our midstream operations are subject to all of the risks and operational hazards inherent in transporting natural gas and ethane and natural gas compression, including:

· damages to pipelines, facilities and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;
· maintenance, repairs, mechanical or structural failures;
· damages to, loss of availability of and delays in gaining access to interconnecting third-party pipeline;
· disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack; and
· leaks of natural gas or ethane as a result of the malfunction of equipment or facilities.

A material event such as those described above could expose us to liabilities, monetary penalties or interruptions in our business operations. Although we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Our current and future levels of indebtedness may adversely affect our results and limit our growth.

At December 31, 2015, we had long-term indebtedness of $4.7 billion, including borrowings of $116 million under our revolving credit facility and $750 million under our term loan credit agreement. The terms of the indentures relating to our outstanding senior notes, our credit facilities, and the master lease agreements relating to our drilling rigs and other equipment, which we collectively refer to as our "financing agreements," impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, which may include, without limitation, one or more of the following:

- incurring additional debt;
- redeeming stock or redeeming debt;
- making investments;
- creating liens on our assets; and
- selling assets.

Under our revolving credit facility and term loan facility, we must keep our total debt at or below 60% of our total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any non-cash impacts from any full cost ceiling impairments, certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our revolving credit facility, our adjusted capital structure as of December 31, 2015, was 38% debt and 62% equity. We were in compliance with all of the covenants of our revolving credit facility as of December 31, 2015. Although we do not anticipate any violations of our financial covenants, our ability to comply with these covenants are dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas, oil and NGLs.

Although the indentures governing the notes contain covenants that apply to us, covenants limiting liens and sale and leaseback covenants contain exceptions and limitations that would allow us, pursuant to the terms of the indenture, to create, grant or incur certain liens or security interests. Moreover, the indentures do not contain any limitations on the ability of us or our subsidiaries to incur debt, pay dividends, make investments, or limit the ability of our subsidiaries to make distributions to us. Such activities may, however, be limited by our other financing agreements in certain circumstances.

Our level of indebtedness and off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;

- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Our ability to comply with the covenants and other restrictions in our financing agreements may be affected by events beyond our control, including prevailing economic and financial conditions.

If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our obligations under the notes or our other financing agreements, and in the case of the lease agreements for drilling rigs, loss of use of our drilling rigs. In particular, a significant or extended decline in natural gas, oil or NGL prices would have a material adverse effect on our results of operations, our access to capital and the quantities of natural gas, oil and NGLs that we can produce economically. For example, the New York Mercantile Exchange, or NYMEX, natural gas prices traded at a high of $3.19 in January 2015 and a low of $2.03 in November 2015 based on last-day-of-month settlement. We may not have sufficient funds to make such payments. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

We have made significant investments in pipelines and gathering systems and contracts and in oilfield service businesses, including our drilling rigs, pressure pumping equipment and sand mine operations, to lower costs and secure inputs for our operations and transportation for our production. If our exploration and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.

Through December 31, 2015, we had invested approximately $1.2 billion in our gas gathering system built for the Fayetteville Shale. We may make further substantial investments in the expansion of this system. Our ability to recover the costs of these investments depends on production from the Fayetteville Shale, and reduced production volumes, whether due to lower drilling activity due to lower prices or failure to produce significant quantities of gas in relevant timeframes, can adversely affect our ability to recover these investments.

We also have entered into gathering agreements in other producing areas and multiple long-term firm transportation agreements relating to natural gas volumes from all our producing areas. As of December 31, 2015, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $8.9 billion. If our development programs fail to produce sufficient quantities of natural gas and ethane within expected timeframes, we could be forced to pay demand or other charges for transportation on pipelines and gathering systems that we would not be using.

We also have made significant investments to meet certain of our field services’ needs, including establishing our own drilling rig operation, sand mine and pressure pumping capability. Reductions in our operating plans caused by the recent drop in commodity prices has caused us to take much of this equipment out of service and has reduced the need for sand and other services. If our level of operations is reduced for a long period, we may not be able to recover these investments. Further, our presence in these service and supply sectors, including competing with them for qualified personnel and supplies, may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers.

We may be unable to dispose of assets on attractive terms, and may be required to retain liabilities for certain matters.

Various factors could materially affect our ability to dispose of assets or complete announced dispositions, including the availability of purchasers willing to purchase the assets at prices acceptable to us, particularly in times of reduced and volatile commodity prices. Sellers typically retain certain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Our business depends on the availability of water and the ability to dispose of water. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

With current technology, water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water, or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection control wells.

In addition, concerns have been raised about the potential for earthquakes to occur from the use of underground injection control wells, a predominant method for disposing of waste water from natural gas and oil activities. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations.

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Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of water necessary for hydraulic fracturing of wells or the disposal of water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our producing properties are concentrated in two regions, the Appalachian Basin and the Fayetteville Shale, making us vulnerable to risks associated with operating in limited geographic areas.

Our producing properties are geographically concentrated in the Fayetteville Shale in Arkansas and the Appalachian Basin in Pennsylvania and West Virginia. At December 31, 2015, 47% of our total estimated proved reserves were attributable to properties located in the Appalachian Basin and 53% in the Fayetteville Shale. As a result of this concentration in two primary regions, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of natural gas, oil or natural gas liquids.

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and oil and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and gas industry. Certain of our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for productive natural gas and oil properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. This may become more likely if prices for oil and NGLs recover faster than prices for natural gas, as natural gas comprises a far greater percentage of our overall production than it does for most of the companies with whom we compete for talent. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Volatility in the financial markets or in global economic factors could adversely impact our business and financial condition.

United States and global economies may experience periods of turmoil and volatility from time to time, which may be characterized by diminished liquidity and credit availability, inability to access capital markets, high unemployment, unstable consumer confidence and diminished consumer spending. In recent periods, there has been significant downward pressure on natural gas, oil and NGL prices, and a continuation of that trend could continue or exacerbate that pressure. This would negatively impact our revenues, margins, profitability, operating cash flows, liquidity and financial condition. Such weakness or uncertainty could also cause our natural gas hedging arrangements or future oil or NGL hedges, if any, to become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Furthermore, our ability to collect receivables may be adversely impacted.

Historically, we have used cash flows from operations, borrowings under our credit facility and proceeds from capital market transactions to fund capital expenditures. Volatility in U.S. and global financial markets, including market disruptions, limited liquidity, and interest rate volatility, may result in our inability to obtain needed capital on acceptable terms or at all and may increase our cost of financing. We have a credit facility with lender commitments totaling $2.0 billion, which may be increased up to a total of $2.5 billion upon agreement with participating lenders, and a term loan credit agreement with lender commitments for an additional $750 million. We also have $3.9 billion in senior notes maturing in various increments from 2017 to 2025. In the future, regardless of our company’s situation, conditions in financial markets may limit our ability to access adequate funding under our credit facility if our lenders are unwilling or unable to meet their funding obligations or increase their commitments under the credit facility. Due to these and other factors, we cannot be certain that funding, if needed, will be available to the extent required or on terms we find acceptable. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, fund our capital program and commitments, complete new property acquisitions to replace reserves, take advantage of business opportunities, respond to competitive pressures, or refinance debt obligations as they come due. Should any of the above risks occur, they could have a material adverse effect on our financial condition, results of operations and cash flows.

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

Our natural gas and oil exploration and production operations are subject to complex and stringent federal, state and local laws and regulations, including those governing environmental protection, the occupational health and safety aspects of our operations, the discharge of materials into the environment, and the protection of certain plant and animal species. See “Other —Environmental Regulation” in Item 1 of Part I of this Annual Report for a description of the laws and regulations that affect us. In order to conduct operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Environmental regulations may restrict the types, quantities and concentration of materials that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenues.

Failure to comply with laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including investigatory actions, the assessment of monetary penalties, the imposition of remedial requirements, or the issuance of orders or judgments limiting or enjoining future operations. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. Moreover, our costs of compliance with existing laws could be substantial and may increase or unforeseen liabilities could be imposed if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. If we are not able to recover the increased costs through insurance or increased revenues, our business, financial condition, results of operations and cash flows could be adversely affected.

Climate change legislation or regulations governing the emissions of “greenhouse gases” could result in increased operating costs and reduce demand for the natural gas, oil and natural gas liquids we produce.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet “best available control technology” standards that will be established on a case-by-case basis. One of our subsidiaries operates compressor stations, which are facilities that are required to adhere to the PSD or Title V permit requirements. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore natural gas and oil production sources in the United States on an annual basis, which include certain of our operations. More recently, in January 2015, the Obama Administration announced that the EPA is expected to finalize in 2016 new regulations that will set methane emission standards for new and modified natural gas and oil production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and natural gas sector by up to 45% from 2012 levels by 2025. The EPA proposed such regulations in 2015.

Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

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Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and natural gas industry, it could have an adverse effect on our business.

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

The Dodd-Frank Act established federal oversight and regulation of the over-the-counter ("OTC") derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC, and other regulatory authorities to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized most of its regulations under the Dodd-Frank Act, it continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, it is not possible at this time to predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations may increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and the regulations thereunder, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures

In November 2013, the CFTC proposed new rules that would place federal limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. If finalized, the position limits rule and its companion rule on aggregation among entities under common ownership or control may have an impact on our ability to hedge our exposure to certain enumerated commodities.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and mandatory trading on designated contract markets or swap execution facilities. The CFTC may designate additional classes of swaps as subject to the mandatory clearing requirement in the future, but has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. The CFTC and prudential banking regulators also recently adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. We expect to qualify for and rely upon an end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge our commercial risks. We will also qualify for an exception from the uncleared swaps margin requirements. However, the application of the mandatory clearing and trade execution requirements and the uncleared swaps margin requirement to other market participants, such as swap dealers, may adversely affect the cost and availability of the swaps that we use for hedging.

Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

As described in more detail under “Critical Accounting Policies and Estimates – Natural Gas and Oil Properties” in Item 7 of Part II of this Annual Report, our reserve data represents the estimates of our reservoir engineers made under the supervision of our management, and our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, oil and NGLs that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas, oil and NGL prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas, oil and NGL reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average natural gas, oil and NGL index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs

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may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Derivative transactions may limit our potential gains and involve other risks.

To manage our exposure to price risk, we currently, and may in the future, enter into derivative arrangements, utilizing commodity derivatives with respect to a portion of our future production. The goal of entering into such derivative agreements is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if natural gas, oil and natural gas liquids prices rise above the price established by the hedge.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our futures contracts fail to perform on their contract obligations; or
- an event materially impacts natural gas, oil or NGL prices or the relationship between the hedged price index and the natural gas, oil or NGL sales price.

We cannot assure you that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, oil or natural gas liquids. Likewise, these transactions may limit our potential gains should prices of natural gas, oil or natural gas liquids rise. Where we choose not to engage in derivative transactions in the future, we may be more adversely affected by changes in natural gas, oil or natural gas liquids prices than our competitors who engage in derivative transactions. Lower natural gas, oil and NGL prices may also negatively impact our ability to enter into derivative contracts at favorable prices.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

The elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies has been proposed in recent years by members of the U.S. Congress and by the President in his fiscal year 2016 budget proposal. These changes have included, among other proposals:

- repeal of the percentage depletion allowance for natural gas and oil properties;
- elimination of current deductions for intangible drilling and development costs;
- elimination of the deduction for certain domestic production activities; and
- extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether these or similar changes will be enacted. The passage of these or any similar changes in U.S. federal income tax laws to eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development could have an adverse effect on our financial position, results of operations and cash flows.

Our Canadian exploration and production activities are subject to different risks and uncertainties, different from or in addition to those we face in our U.S. operations.

In addition to the various risks associated with our U.S. operations, we are subject to risks and uncertainties related to our Canadian exploration and production activities, including risks related to increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, restrictions on imports and exports, expropriation of property, cancellation of contract rights, environmental protection controls, environmental compliance requirements and laws pertaining to workers' health and safety. Consequently, our exploration, development and production activities in Canada could be substantially affected by factors beyond our control. In addition, the rights of aboriginal peoples, called First Nations in Canada, are not clear. Our operations in New Brunswick have been subject to local protests, causing several temporary interruptions to our exploration activities. In December 2014, New Brunswick's provincial government announced its intent to impose a moratorium on hydraulic fracturing in the province, and, on March 27, 2015, the provincial legislature approved enabling legislation. We have been granted an extension of our licenses. The provincial government has announced a list of conditions that must be met before the moratorium can be lifted, but because these conditions are subjective and the government has discretion whether to grant an extension, we cannot predict the duration of the moratorium or whether it will continue beyond the expiration of the licenses, as their terms have been extended. Unless and until the moratorium is lifted, we will not be able to continue with our program in New Brunswick. If the licenses expire before the moratorium is lifted or we can complete our program, we may be required to write off our investment.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, analyze seismic and drilling information, conduct reservoir modeling and reserves estimation, communicate with employees and business associates, perform compliance reporting and in many other activities related to our business. Our business associates, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. Our technologies, systems, networks, and those of our business associates may become the target of cyber attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release of confidential or protected information, corruption of data or other disruptions of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber attack involving our information systems and related infrastructure, or that of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including:

- unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for natural gas and oil resources;
- unauthorized access to personal identifying information of royalty owners, employees and vendors, which could expose us to allegations that we did not sufficiently protect that information;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects; and
- a cyber attack on a third party gathering, pipeline, or rail service provider could delay or prevent us from marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability, which could have a material adverse effect on our financial condition, results of operations or cash flows.

To date we have not experienced any material losses relating to cyber attacks; however, there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, oil spills, and explosions of natural gas transmission lines, may lead to regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

Common stockholders will be diluted if additional shares are issued.

In January 2015, we issued 30.0 million shares of common stock and 34.5 million depositary shares representing the 1/20th interest in our 6.25% Series B Mandatory Preferred Stock, which will convert into a minimum of approximately 64 million or a maximum of 75 million shares of common stock by January 2018, to refinance a portion of the debt we incurred to purchase acreage in West Virginia and southwest Pennsylvania. We also issue restricted stock, options and performance share units to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Anti-takeover provisions in our organizational documents and under Delaware law may impede or discourage a takeover, which could cause the market price of our common stock to decline.

We are a Delaware corporation, and the anti-takeover provisions of Delaware law impose various impediments to the ability of a third party to acquire control of us, even if a change in control would be beneficial to our existing stockholders, which, under certain circumstances, could reduce the market price of our common stock. In addition, protective provisions in our Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws or the implementation by our board of directors of a stockholder rights plan that could deter a takeover.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2015 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2015 Proved Reserves by Category and Summary Operating Data" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Annual Report and incorporated by reference into this Item 2.

The information regarding our proved undeveloped reserves required by Item 1203 of Regulation S-K is included under the heading "Proved Undeveloped Reserves" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Annual Report.

The information regarding delivery commitments required by Item 1207 of Regulation S-K is included under the heading "Sales, Delivery Commitments and Customers" in the "Business – Exploration and Production – Our Operations" in Item 1 of this Annual Report and incorporated by reference into this Item 2. For additional information about our natural gas and oil operations, we refer you to Note 4 to the consolidated financial statements. For information concerning capital investments, we refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Investments." We also refer you to Item 6, "Selected Financial Data" in Part II of this Annual Report for information concerning natural gas, oil and NGLs produced.

The information regarding natural gas and oil properties, wells, operations and acreage required by Item 1208 of Regulation S-K is set forth below.

Leasehold acreage as of December 31, 2015:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Appalachia:				
Northeast (1)	196,166	168,753	106,518	101,582
Southwest (2)	348,604	193,582	342,223	231,516
Fayetteville Shale (3)	472,818	288,569	1,059,158	669,072
New Ventures:				
USA New Ventures – Brown Dense (4)	256,287	196,598	4,903	4,493
USA New Ventures – Sand Wash Basin (5)	349,796	243,493	11,181	7,985
USA New Ventures – Other (6)	722,248	504,526	–	–
Canada New Ventures (7)	2,716,758	2,716,758	–	–
	5,062,677	4,312,279	1,523,983	1,014,648

(1) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 30,172 net acres in 2016, 57,724 net acres in 2017 and 12,891 net acres in 2018.
(2) Assuming successful wells are not drilled to develop the acreage and leases are not extended leasehold expiring over the next three years will be 36,934 net acres in 2016, 42,034 net acres in 2017 and 12,604 net acres in 2018. Of this acreage, 16,160 net acres in 2016, 15,262 net acres in 2017 and 1,990 net acres in 2018 can be extended for an average of an additional 4.8 years.
(3) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 164 net acres in 2016, 453 net acres in 2017 and 31 net acres in 2018 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management). Includes 31,413 net undeveloped acres and 170,743 net developed acres in the Arkoma Basin that have previously been reported as a component of our conventional Arkoma acreage.

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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 58,849 net acres in 2016, 68,790 net acres in 2017 and 67,528 net acres in 2018.
(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 85,767 net acres in 2016, 35,883 net acres in 2017 and 55,918 net acres in 2018.
(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 206,567 net acres in 2016, 69,447 net acres in 2017 and 22,286 net acres in 2018.
(7) Assuming successful wells are not drilled to develop the acreage and our exploration license agreements are not extended, leasehold expiring over the next three years will be 48,960 net acres in 2016, 148,480 net acres in 2017 and 800 net acres in 2018.

Producing wells as of December 31, 2015:

	Natural Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Appalachia:							
Northeast (1)	774	407	–	–	774	407	424
Southwest	1,085	859	–	–	1,085	859	994
Fayetteville Shale	4,268	2,971	–	–	4,268	2,971	3,756
New Ventures	12	9	8	8	20	17	20
	6,139	4,246	8	8	6,147	4,254	5,194

(1) Includes 316 gross natural gas wells in which we own an overriding royalty interest.

The information regarding drilling and other exploratory and development activities required by Item 1205 of Regulation S-K is set forth below:

	Exploratory(1)					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2015	3.0	3.0	–	–	3.0	3.0
2014	12.0	11.9	–	–	12.0	11.9
2013	8.0	7.8	1.0	1.0	9.0	8.8

	Development(1)					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net

2015	427.0	344.4	–	–	427.0	344.4
2014	572.0	466.1	–	–	572.0	466.1
2013(2)	527.0	468.8	3.0	1.5	530.0	470.3

(1) We have not drilled any exploratory or development wells in Canada in the past three years.
(2) 2013 dry wells include 2 gross wells in the Fayetteville Shale that were plugged and abandoned after being spud due to changes in the development plans.

The following table presents the information regarding our present activities required by Item 1206 of Regulation S-K:

Wells in progress as of December 31, 2015: (1,2)

	Gross	Net
Drilling:		
Exploratory	1	1
Development	47	47
Total	48	48
Completing:		
Exploratory	1	1
Development	154	130
Total	155	131
Drilling & Completing:		
Exploratory	2	2
Development	201	177
Total	203	179

(1) As of December 31, 2015, we did not have any drilling activities in Canada.
(2) Includes 41 wells that are waiting on pipeline or production facilities.

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The information regarding oil and gas production, production prices and production costs required by Item 1204 of Regulation S-K is set forth below:

Production, Average Sales Price and Average Production Cost:

	For the years ended December 31,		
	2015	2014	2013
Natural Gas			
Production (Bcf):			
Northeast Appalachia	360	254	151
Southwest Appalachia	67	2	–
Fayetteville Shale	465	494	486
Other	7	16	19
Total	899	766	656
Average gas price per Mcf, excluding hedges:			
Northeast Appalachia	$ 1.62	$ 3.48	$ 3.25
Southwest Appalachia	1.92	3.61	–
Fayetteville Shale	2.12	3.86	3.13
Total	$ 1.91	$ 3.74	$ 3.17
Average realized gas price per Mcf, including hedges	$ 2.37	$ 3.72	$ 3.65
Oil			
Production (MBbls):			
Southwest Appalachia	2,036	45	–
Other	229	190	138
Total	2,265	235	138
Average oil price per Bbl:			
Southwest Appalachia	$ 31.80	$ 41.28	$ –
Other	46.21	89.04	103.32
Total	$ 33.25	$ 79.91	$ 103.32
NGL			
Production (MBbls):			
Southwest Appalachia	10,640	182	–
Other	62	49	50
Total	10,702	231	50
Average NGL price per Bbl:			
Southwest Appalachia	$ 6.76	$ 10.44	$ –
Other	14.51	35.22	43.63

Total	$ 6.80	$ 15.72	$ 43.63
Total Production (Bcfe):			
Northeast Appalachia	360	254	151
Southwest Appalachia	143	3	–
Fayetteville Shale	465	494	486
Other	8	17	20
Total	976	768	657
Average Production Cost			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Northeast Appalachia	$ 0.71	$ 0.83	$ 0.80
Southwest Appalachia	1.39	1.17	–
Fayetteville Shale	0.91	0.92	0.86
Total	$ 0.92	$ 0.91	$ 0.86

During 2015, we were required to file Form 23, "Annual Survey of Domestic Oil and Gas Reserves," with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 4 to the consolidated financial statements in Item 8 to this Annual Report. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties of which we are the operator.

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Miles of Pipe

As of December 31, 2015, our Midstream Services segment had 2,044 miles and 16 miles of pipe in its gathering systems located in Arkansas and Louisiana, respectively.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than that we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Generally, before we commence drilling operations on properties that we operate, we conduct a title examination and perform curative work with respect to significant defects that we identify. We believe that we have performed title examination with respect to substantially all of our active properties that we operate.

ITEM 3. LEGAL PROCEEDINGS

We are subject to litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management’s view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. See “Litigation” in Note 9, “Commitments and Contingencies” in the consolidated financial statements for further details on our current legal proceedings.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Our sand mining operations in support of our E&P business are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange (the “NYSE”) under the symbol “SWN.” On February 23, 2016, the closing price of our common stock trading under the symbol “SWN” was $6.63 and we had 3,416 stockholders of record, respectively. The following table presents the high and low sales prices for closing market transactions for our common stock trading under the symbol “SWN” as reported on the NYSE.

	Range of Market Prices					
Quarter Ended	2015		2014		2013	
March 31	$ 27.97	$ 21.63	$ 46.57	$ 38.01	$ 38.86	$ 32.09
June 30	$ 29.25	$ 22.49	$ 48.93	$ 44.33	$ 39.58	$ 34.97
September 30	$ 22.17	$ 12.11	$ 44.99	$ 34.95	$ 39.91	$ 36.38
December 31	$ 13.59	$ 5.15	$ 36.50	$ 27.24	$ 40.18	$ 35.16

We do not currently pay quarterly cash dividends on our common stock.

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Issuer Purchases of Equity Securities

The table below sets forth information with respect to purchases of our common stock made by us or on our behalf during the quarter ended December 31, 2015:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
December 1 - 31, 2015	71,911	$ 7.69	n/a	n/a
Total fourth-quarter 2015:	71,911	$ 7.69	n/a	n/a

(1) Reflects shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances. All changes in common stock in treasury in 2015 were due to purchases and sales of shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement savings plan.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2015, 2014 or 2013. See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," in Part III of this Annual Report for information regarding our equity compensation plans as of December 31, 2015.

STOCK PERFORMANCE GRAPH

The following graph compares, for the last five years, the performance of our common stock to the S&P 500 Index and our peer group. Our peer group was expanded in 2015 to reflect the companies whose performance metrics are currently used in determining our annual incentive awards and includes Anadarko Petroleum Corporation, Apache Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Concho Resources Inc., Continental Resources Inc., Denbury Resources Inc., Devon Energy Corporation, EOG Resources, Inc., EQT Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Co., QEP Resources, Inc., Range Resources Corporation, Sandridge Energy, Inc., SM Energy Company, Ultra Petroleum Corp., Whiting Petroleum Corporation and WPX Energy, Inc. The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2010, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.

	12/31/10	12/31/11	12/31/12	12/31/13	12/31/14	12/31/15
Southwestern Energy Company	$ 100	$ 85	$ 89	$ 105	$ 73	$ 19
S&P 500 Index	100	102	118	157	178	181
Peer Group	100	94	92	122	103	68

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2015. This information and the notes thereto are derived from our consolidated financial statements. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Financial Statements and Supplementary Data."

	2015	2014	2013	2012	2011
	(in millions except shares, per share, stockholder data and percentages)				
Financial Review					
Operating revenues:					
Exploration and production	$ 2,074	$ 2,862	$ 2,404	$ 1,964	$ 2,099
Midstream services	3,119	4,358	3,347	2,363	2,860
Other	–	–	–	3	3
Intersegment revenues	(2,060)	(3,182)	(2,380)	(1,600)	(2,010)
	3,133	4,038	3,371	2,730	2,952
Operating costs and expenses:					
Marketing purchases – midstream services	852	980	782	592	709
Operating and general and administrative expenses	935	648	519	420	399
Depreciation, depletion and amortization	1,091	942	787	811	705
Impairment of natural gas and oil properties	6,950	–	–	1,940	–
Gain on sale of assets, net	(283)	–	–	–	–
Taxes, other than income taxes	110	95	79	68	66
	9,655	2,665	2,167	3,831	1,879
Operating income (loss)	(6,522)	1,373	1,204	(1,101)	1,073
Interest expense, net	56	59	42	35	24
Other income (loss), net	(30)	(4)	2	1	–
Gain (loss) on derivatives	47	139	26	(15)	2
Income (loss) before income taxes	(6,561)	1,449	1,190	(1,150)	1,051
Provision (benefit) for income taxes:					
Current	(2)	21	(11)	19	4

Deferred	(2,003)	504	497	(462)	409
	(2,005)	525	486	(443)	413
Net income (loss)	$ (4,556)	$ 924	$ 704	$ (707)	$ 638
Mandatory convertible preferred stock dividend	106	–	–	–	–
Net income (loss) Attributable to Common Stock	$ (4,662)	$ 924	$ 704	$ (707)	$ 638
Return on equity	(204.3%)	19.8%	19.4%	(23.3%)	16.1%
Net cash provided by operating activities	$ 1,580	$ 2,335	$ 1,909	$ 1,654	$ 1,740
Net cash used in investing activities	$ (1,638)	$ (7,288)	$ (2,216)	$ (1,907)	$ (2,025)
Net cash provided by financing activities	$ 20	$ 4,983	$ 277	$ 291	$ 284
Common Stock Statistics					
Earnings per share:					
Net income (loss) attributable to common stockholders – Basic	$ (12.25)	$ 2.63	$ 2.01	$ (2.03)	$ 1.84
Net income (loss) attributable to common stockholders – Diluted	$ (12.25)	$ 2.62	$ 2.00	$ (2.03)	$ 1.82
Book value per average diluted share	$ 6.00	$ 13.23	$ 10.32	$ 8.71	$ 11.34
Market price at year-end	$ 7.11	$ 27.29	$ 39.33	$ 33.41	$ 31.94
Number of stockholders of record at year-end	3,415	3,271	3,259	3,122	3,083
Average diluted shares outstanding	380,521,039	352,410,683	351,101,452	348,610,503	349,921,413

	2015	2014	2013	2012	2011
Capitalization (in millions)					
Total debt	$ 4,729	$ 6,967	$ 1,951	$ 1,669	$ 1,343
Total equity	2,282	4,662	3,622	3,036	3,969
Total capitalization	$ 7,011	$ 11,629	$ 5,573	$ 4,705	$ 5,312
Total assets	$ 8,110	$ 14,925	$ 8,048	$ 6,738	$ 7,903
Capitalization ratios:					
Debt	67%	60%	35%	35%	25%
Equity	33%	40%	65%	65%	75%
Capital Investments (in millions) (1)					
Exploration and production	2,258	7,254	2,052	1,861	1,978
Midstream services	167	144	158	165	161
Other	12	49	25	55	68
	$ 2,437	$ 7,447	$ 2,235	$ 2,081	$ 2,207
Exploration and Production					
Natural gas:					
Production, Bcf	899	766	656	565	499
Average realized price per Mcf, including hedges	$ 2.37	$ 3.72	$ 3.65	$ 3.44	$ 4.18
Average price per Mcf, excluding hedges	$ 1.91	$ 3.74	$ 3.17	$ 2.34	$ 3.56
Oil:					
Production, MBbls	2,265	235	138	83	97
Average price per barrel	$ 33.25	$ 79.91	$ 103.32	$ 101.54	$ 94.08
NGL:					
Production, MBbls	10,702	231	50	–	–
Average price per barrel	$ 6.80	$ 15.72	$ 43.63	$ –	$ –
Total production, Bcfe	976	768	657	565	500
Lease operating expenses per Mcfe	$ 0.92	$ 0.91	$ 0.86	$ 0.80	$ 0.84
General and administrative expenses per Mcfe	$ 0.21	$ 0.24	$ 0.24	$ 0.26	$ 0.27
Taxes, other than income taxes per Mcfe	$ 0.10	$ 0.11	$ 0.10	$ 0.10	$ 0.11
Proved reserves at year-end:					
Natural gas, Bcf	5,917	9,809	6,974	4,017	5,887
Oil, MMBbls	8.8	37.6	0.4	0.2	1
NGLs, MMBbls	40.9	118.7	–	–	–
Total reserves, Bcfe	6,215	10,747	6,976	4,018	5,893

Midstream Services					
Volumes marketed, Bcfe	1,127	904	786	676	611
Volumes gathered, Bcf	799	963	900	846	746

(1) Capital investments include a decrease of $33 million for 2015, an increase of $155 million for 2014, decreases of $25 million and $37 million for 2013 and 2012, respectively, and an increase of $4 million for 2011 related to the change in accrued expenditures between years.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis is the Company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the Company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "anticipate," "intend," "plan," "project," "estimate," "continue," "potential," "should," "could," "may," "will," "ob "guidance," "outlook," "effort," "expect," "believe," "predict," "budget," "projection," "goal," "forecast," "target" or similar w forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "Cautionary Statement about Forward-Looking Statements."

OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, "we", "our", "us" or "Southwestern") is an independent energy company engaged in natural gas and oil exploration, development and production, which we refer to as 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 operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration, development and production of natural gas and oil. Our current operations are principally focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania, which we refer to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Our operations in West Virginia, which we refer to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, we refer to our properties located in Pennsylvania and West Virginia as the "Appalachian Basin." Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. 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." Under our New Ventures operations, we have exploration and production activities ongoing in Colorado and Louisiana, along with other areas in which we are currently exploring for new development opportunities. We operate drilling rigs and provide oilfield products and services, principally serving our exploration and production operations, though the level of these services in 2016 will depend upon our capital investing for the year. Our natural gas gathering and marketing activities primarily support our E&P activities in Arkansas, Pennsylvania, Louisiana and West Virginia.

We are focused on providing long-term growth in the net asset value per share of our business. Historically, the vast majority of our operating income and cash flow has been derived from the production associated with our E&P business. However, in 2015, depressed commodity prices significantly decreased our E&P results of operations. The price we expect to receive for our production is a critical factor in the capital investments we make in order to develop our properties. In 2016, we expect to have decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the lower commodity price environment. We anticipate adjusting our activity levels throughout our portfolio and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sales prices for our production. Going forward, we will be impacted by crude oil and natural gas liquids (“NGLs”) prices which have been volatile and have recently declined significantly. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the first quarter of 2016 ranging from approximately $300 million to $500 million, net of tax, when excluding future changes in costs excluded from amortization, with likely material impairments continuing beyond the first quarter.

Recent Financial and Operating Results

In 2015, our net loss attributable to common stock was $4,662 million, or ($12.25) per diluted share, down from net income of $924 million, or $2.62 per diluted share, in 2014. Our net income was $704 million, or $2.00 per diluted share, in 2013. In 2015, we incurred non-cash impairments of our natural gas and oil properties totaling $6,950 million, or $4,287 million net of taxes, that resulted from a significant decline in natural gas prices during 2015.

In 2015, our natural gas and liquids production increased 27% to 976 Bcfe, up from 768 Bcfe in 2014. The 208 Bcfe increase in our 2015 production resulted from a 140 Bcfe increase in net production from our Southwest Appalachia properties, a 106 Bcf increase in net production from our Northeast Appalachia properties and was offset by a 38 Bcfe decrease in net production from our Fayetteville Shale and other properties. In 2014, our natural gas and liquids production increased to 768 Bcfe, up from 657 Bcfe in 2013. The 111 Bcfe increase in our 2014 production resulted from a 103 Bcf increase in net production from our Northeast Appalachia properties and an 8 Bcf increase in net production from our Fayetteville Shale properties.

Our year-end reserves decreased 42% in 2015 to 6,215 Bcfe, down from 10,747 Bcfe at the end of 2014 and 6,976 Bcfe at the end of 2013. The overall decrease in total estimated proved reserves in 2015 was primarily due to downward price revisions associated with decreased commodity prices, partially offset by upward performance revisions in Northeast and Southwest Appalachia. The overall increase in total estimated proved reserves in 2014 was primarily due to the acquisition of approximately 413,000 net acres in Southwest Appalachia which increased reserves by 33%, our successful drilling programs in the Fayetteville Shale and Northeast Appalachia and upward performance revisions in Northeast Appalachia where reserves grew 63% from 2013.

Our E&P segment operating loss was $7,104 million in 2015, down from operating income of $1,013 million in 2014. The operating loss in 2015 included non-cash impairments of natural gas and oil properties totaling $6,950 million. Excluding the non-cash impairments, operating income in 2015 decreased $1,167 million from 2014 as the revenue impact of our 27%, or 208 Bcfe, increase in production was more than offset by a 36%, or $1.35, decrease in our average realized natural gas price and a $379 million increase in operating costs and expenses that resulted from our production growth. Operating income was $1,013 million in 2014, up from operating income of $879 million in 2013. Operating income in 2014 increased $134 million over 2013 as the revenue impact of our 17%, or 111 Bcfe, increase in production and 2%, or $0.07, increase in our average realized natural gas price more than offset the $324 million increase in operating costs that resulted from our production growth. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $27 and $21 million in operating income for the years ended December 31, 2014 and 2013, respectively.

Operating income for our Midstream Services segment was $583 million in 2015, up from $361 million in 2014 and $325 million in 2013. Operating income for our Midstream Services segment increased in 2015 due to a $277 million net gain on sale of assets and a $13 million decrease in operating costs and expenses, exclusive of marketing purchase costs, partially offset by a decrease of $71 million in gathering revenues, which resulted from decreased volumes gathered. Volumes gathered decreased to 799 Bcf in 2015, compared to 963 Bcf in 2014. In the second quarter of 2015, we sold our northeast Pennsylvania and East Texas gathering assets that accounted for $13, $35 and $23 million in operating income for the years ended December 31, 2015, 2014 and 2013, respectively. A net gain of $277 million was recognized and is included in gain on sale of assets, net in the consolidated statement of operations. Operating income for our Midstream Services segment increased in 2014 due to an increase of $46 million in gathering revenues and a $12 million increase in the margin generated from our natural gas marketing activities, which was partially offset by a $22 million increase in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our growth in volumes gathered. Volumes gathered grew to 963 Bcf in 2014 compared to 900 Bcf in 2013.

We had total capital investments of $2.4 billion in 2015, compared to $7.4 billion in 2014 and $2.2 billion in 2013. Of our total capital investments, $2.3 billion was invested in our E&P segment in 2015, which included $533 million related to acquisitions, compared to $7.3 billion in 2014, which included $5.2 billion primarily related to the December 2014 acquisition of certain oil and natural gas assets in Southwest Appalachia from Chesapeake Energy Corporation (the “Chesapeake Property Acquisition”), and $2.1 billion in 2013, which included $96 million primarily related to the acquisition of properties in Northeast Appalachia. Our Midstream Services capital investments for 2015 included $109 million related to the acquisition from WPX.

Outlook

We are exercising capital discipline by aligning our 2016 capital investing program within our expected cash flow. We will also look for opportunities to strengthen our balance sheet, maximize margins in each core area of our business and continue to seek alternative means to further our knowledge of our asset base. We believe that 2016 will be a challenging year for our business due to the depressed commodity price environment and continued uncertainty of natural gas and oil prices in the United States. However, we expect that our resource base, financial flexibility and disciplined investment of capital will position us for success when commodity prices ultimately recover.

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RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense and income tax expense are discussed on a consolidated basis.

Exploration and Production

	For the years ended December 31,		
	2015	2014	2013
Revenues (in millions)	$ 2,074	$ 2,862	$ 2,404
Impairment of natural gas and oil properties (in millions)	$ 6,950	$ –	$ –
Operating costs and expenses (in millions)	$ 2,228	$ 1,849	$ 1,525
Operating income (loss) (in millions)	$ (7,104)	$ 1,013	$ 879
Gain on derivatives (in millions) (1)	$ 206	$ 9	$ 5
Gas production (Bcf)	899	766	656
Oil production (MBbls)	2,265	235	138
NGL production (MBbls)	10,702	231	50
Total production (Bcfe)	976	768	657
Average realized gas price per Mcf, including hedges (2)	$ 2.37	$ 3.72	$ 3.65
Average realized gas price per Mcf, excluding hedges	$ 1.91	$ 3.74	$ 3.17
Average oil price per Bbl	$ 33.25	$ 79.91	$ 103.32
Average NGL price per Bbl	$ 6.80	$ 15.72	$ 43.63
Average unit costs per Mcfe:			
Lease operating expenses	$ 0.92	$ 0.91	$ 0.86
General & administrative expenses	$ 0.21	$ 0.24	$ 0.24
Taxes, other than income taxes	$ 0.10	$ 0.11	$ 0.10
Full cost pool amortization	$ 1.00	$ 1.10	$ 1.08

(1) Represents the gain (loss) on derivatives, settled, associated with derivatives not designated for hedge accounting.

(2) Including the gain (loss) on derivatives excluding derivatives, settled effects of commodity hedging contracts not designated for hedge accounting, results in an average price of $2.20, $3.90 and $3.68 for the years ended December 31, 2015, 2014 and 2013, respectively.

Revenues

Revenues for our E&P segment were down $788 million, or 28%, in 2015 compared to 2014. A decrease in the price realized from the sale of our natural gas production decreased revenue by $1,647 million in 2015, partially offset by an increase of $497 million due to higher natural gas production volumes and an increase of $235 million in hedge settlement proceeds. Additionally, there was a $328 million increase due to increased liquids production related to our Southwest Appalachia property acquisition partially offset by a $201 million decrease due to decreased liquids pricing. E&P revenues were up $458 million, or 19%, in 2014 compared to 2013. Higher natural gas production volumes in 2014 increased revenue by $403 million and higher realized prices for our natural gas production increased revenue by $55 million. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $15, $70 and $68 million of our gas and oil revenues for the years ended December 31, 2015, 2014 and 2013, respectively. In 2016, we expect to have decreased activity in our Appalachian Basin and Fayetteville Shale assets as a result of the lower commodity price environment.

Production

In 2015, our natural gas and liquids production increased 27% to 976 Bcfe, up from 768 Bcfe in 2014, and was produced entirely by our properties in the United States. The 208 Bcfe increase in our 2015 production resulted from a 140 Bcfe increase in net production from our Southwest Appalachia properties, a 106 Bcf increase in net production from our Northeast Appalachia properties, partially offset by 29 Bcf and 9 Bcfe decreases in net production in our Fayetteville Shale and other properties, respectively. In 2014, our natural gas and liquids production increased to 768 Bcfe, up from 657 Bcfe in 2013. The 111 Bcfe increase in our 2014 production resulted from a 103 Bcf increase in net production from our Northeast Appalachia properties and an 8 Bcfe increase in net production in our Fayetteville Shale and other properties. Our net production from Northeast Appalachia was 360 Bcf in 2015, up from 254 Bcf in 2014 and 151 Bcf in 2013. Our net production from Southwest Appalachia was 143 Bcfe in 2015, up from 3 Bcfe in 2014; we owned no properties in this area before late December 2014. Our net production from the Fayetteville Shale was 465 Bcf in 2015, down from 494 Bcf in 2014 and 486 Bcf in 2013.

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Natural gas accounted for approximately 92%, 100% and 100% of our total production for the years ended December 31, 2015, 2014 and 2013, respectively. Oil and NGLs accounted for 1% and 7%, respectively, of our total production for the year ended December 31, 2015.

Our ability to discover, develop and produce reserves is dependent upon a number of factors, many of which are beyond our control, including the availability of capital, availability of transportation, weather, the timing and extent of changes in natural gas and oil prices and competition. There are also many risks inherent in the discovery, development and production of natural gas and oil. We refer you to “Risk Factors” in Item 1A of Part I of this Annual Report for a discussion of these risks and the impact they could have on our financial condition and results of operations.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, decreased 36% to $2.37 per Mcf in 2015, compared to an increase of 2% in 2014 to $3.72 per Mcf from 2013 levels. The decrease in 2015 was the result of a $1.83 decrease in the average natural gas price, excluding hedges, partially offset by higher proceeds from our hedging activities in 2015 as compared to 2014. The increase in 2014 compared to 2013 was primarily the result of increased natural gas prices as our hedging activities marginally decreased our average realized price. In 2015, our hedging activities increased the average natural gas sales price we realized by $0.46 per Mcf, compared to a decrease of $0.02 per Mcf in 2014 and an increase of $0.48 per Mcf in 2013. Disregarding the impact of hedges, the average realized sales price we received for our natural gas production in 2015 was $1.83 per Mcf lower than 2014 and $0.75 lower than the average monthly NYMEX settlement price for 2015.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to heating content of the gas, locational basis differentials, transportation charges and fuel charges. Additionally, we receive a sales price for our oil and NGLs at a difference to average monthly West Texas Intermediate settlement and Mont Belvieu NGL composite prices, respectively, due to a number of factors including product quality, composition, and types of NGLs sold, locational basis differentials, transportation and fuel charges.

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to Item 7A of this Annual Report, Note 5 to the consolidated financial statements, and our hedge risk factor for additional discussion about our derivatives and risk management activities.

As of December 31, 2015, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 216 Bcf and 67 Bcf of our 2016 and 2017 production, respectively, and expected natural gas production through physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.16) per Mcf and ($0.20) per Mcf for 2016 and 2017, respectively. Additionally, we have financial hedges in place on 5 Bcf of our 2016 production at a weighted average basis differential of $0.75 per Mcf.

We realized an average sales price of $33.25 per barrel for our oil production for the year ended December 31, 2015, down approximately 58% from the prior year. The 2014 average realized price of $79.91 per barrel was down 23% from 2013. We did not hedge our 2015, 2014 or 2013 oil production. We realized an average sales price of $6.80 per barrel for our NGL production for the year ended December 31, 2015, down approximately 57% from the prior year. The 2014 average realized price of $15.72 per barrel was down 64% from 2013. We did not hedge our 2015, 2014, or 2013 NGL production.

Operating Income

Our E&P segment operating loss was $7,104 million in 2015, down from an operating income of $1,013 million in 2014. The operating loss in 2015 included non-cash impairments of natural gas and oil properties totaling $6,950 million. Excluding the non-cash impairments, operating income in 2015 decreased $1,167 million over 2014 as the revenue impact of our 27%, or 208 Bcfe, increase in production was more than offset by a 36%, or $1.35, decrease in our average realized natural gas price and a $379 million increase in operating costs and expenses that resulted from our production growth. E&P segment operating income was $1,013 million in 2014, up from operating income of $879 million in 2013. Operating income in 2014 increased $134 million over 2013 as the revenue impact of our 17%, or 111 Bcfe, increase in production and 2%, or $0.07, increase in our average realized natural gas prices more than offset the $324 million increase in operating costs and expenses that resulted from our significant production growth. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $27 and $21 million of our operating income (loss) for the years ended December 31, 2014 and 2013, respectively.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.92 in 2015, compared to $0.91 in 2014 and $0.86 in 2013. Lease operating expenses per unit of production increased in 2015 primarily due to an increase in gathering and processing charges associated with our Southwest Appalachia operations. Lease operating expenses per unit of production increased in 2014 compared to 2013 primarily due to an increase in gathering and compression charges.

General and administrative expenses for the E&P segment were $0.21 per Mcfe in 2015, down from $0.24 per Mcfe in 2014 and 2013. The decrease in general and administrative costs per Mcfe in 2015 was primarily due to an increase in production volumes. In total, general and administrative expenses for the E&P segment were $207 million in 2015, $182 million in 2014 and $157 million in 2013. The increase in general and administrative expenses in 2015 was primarily a result of increased personnel and technological costs associated with the expansion of our E&P operations, due to the acquisition of our Southwest Appalachia assets, and accounted for $21 million, or 85%, of the 2015 increase. The increase in general and administrative expenses in 2014 was primarily due to increased personnel cost, information system related costs and training costs, offset slightly by decreased professional fees. This net increase accounted for $22 million, or 88%, of the 2014 increase. Our E&P employees decreased by 155 during 2015 as compared to 132 employees added in 2014. In January 2016, as a result of lower anticipated drilling activity due to a prolonged depressed commodity price environment, we announced a workforce reduction of approximately 1,100 employees which should be substantially complete by the end of the first quarter of 2016. We expect to record a pre-tax charge to earnings in the first quarter of 2016 of approximately $60 to $70 million.

Taxes other than income taxes per Mcfe were $0.10, $0.11 and $0.10 in 2015, 2014 and 2013, respectively. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $1.00 per Mcfe for 2015, $1.10 per Mcfe for 2014 and $1.08 per Mcfe for 2013. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.

Unevaluated costs excluded from amortization were $3.7 billion at December 31, 2015, compared to $4.6 billion in 2014 and $1.0 billion in 2013. The decrease in unevaluated costs since December 31, 2014 primarily resulted from our evaluation of a portion of our recently acquired Southwest Appalachia assets. Unevaluated costs excluded from amortization at the end of 2015 included $50 million related to our properties in Canada. The increase in unevaluated costs from December 31, 2013 to December 31, 2014 primarily resulted from the Chesapeake Property Acquisition. See Note 4 to the consolidated financial statements for additional information regarding our unevaluated costs excluded from amortization.

The timing and amount of production and reserve additions could have a material impact on our per unit costs.

Midstream Services

	For the years ended December 31,		
	2015	2014	2013
	($ in millions, except volumes)		
Marketing revenues	$ 2,628	$ 3,797	$ 2,830
Gas gathering revenues	$ 491	$ 562	$ 516
Marketing purchases	$ 2,566	$ 3,738	$ 2,783
Operating costs and expenses	$ 247	$ 260	$ 238
Gain on sale of assets, net	$ 277	$ –	$ –
Operating income	$ 583	$ 361	$ 325
Volumes marketed (Bcfe)	1,127	904	786
Volumes gathered (Bcf)	799	963	900

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Revenues

Revenues from our marketing activities were down 31% to $2.6 billion for 2015 compared to 2014 as a 25% increase in volumes marketed was more than offset by a 45% decrease in the prices received for volumes marketed. Revenues from our marketing activities were up 34% to $3.8 billion for 2014 compared to 2013 primarily due to a 17% increase in the average price received for volumes marketed and a 15% increase in volumes marketed. Of the total natural gas volumes marketed, production from our E&P operated wells accounted for 97% in 2015, 97% in 2014 and 96% in 2013. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in marketing purchase expenses. Our Midstream Services segment marketed approximately 60% of our combined oil and NGL production for the year ended December 31, 2015.

Revenues from our gathering activities were down 13% to $491 million for 2015 compared to 2014, primarily from a 17% decrease in natural gas volumes gathered in 2015. Revenues from our gathering activities were up 9% to $562 million for 2014 compared to 2013, primarily due to a 7% increase in natural gas volumes gathered in 2014. The decrease in gathering revenues for 2015 was primarily due to the divestiture of our northeast Pennsylvania and East Texas gathering assets. The divested gathering assets accounted for $21 million, $67 million and $48 million of our gathering revenues for the years ended December 31, 2015, 2014 and 2013, respectively.

Operating Income

Operating income from our Midstream Services segment increased 61% to $583 million in 2015 and increased 11% to $361 million in 2014. The increase in operating income in 2015 includes a $277 million net gain related to the sale of our northeast Pennsylvania and East Texas gathering assets. Excluding this gain, operating income decreased 15% to $306 million in 2015 primarily due to a decrease in volumes gathered resulting from lower production volumes in the Fayetteville Shale and the sale of our northeast Pennsylvania and East Texas gathering assets. A decrease of $71 million in natural gas gathering revenues was only slightly offset by a $13 million decrease in operating costs and expenses, exclusive of marketing purchases, and a $3 million increase in the margin generated by our marketing activities. The increase in operating income for 2014 compared to 2013 was due to a $46 million increase in gathering revenues and an increase of $12 million in the margin generated from our natural gas marketing activities, partially offset by a $22 million increase in operating costs and expenses, exclusive of purchased natural gas costs, associated with the increase in natural gas volumes gathered. The divested gathering assets accounted for $13 million, $35 million and $23 million of our operating income for the years ended December 31, 2015, 2014 and 2013, respectively.

The margin generated from marketing activities was $62 million for 2015, compared to $59 million for 2014 and $47 million for 2013. Margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increases in margins generated are primarily the result of a 25% increase in volumes marketed in 2015 and a 15% increase in volumes marketed in 2014, as compared to prior years, resulting from the marketing of our increased E&P production volumes. We enter into hedging activities from time to time with respect to our natural gas marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Item 7A of Part II of this Annual Report and Note 5 to the consolidated financial statements.

Interest Expense

Interest expense, net of capitalization, was $56 million in 2015, a decrease of $3 million compared to 2014, as an increase in gross interest expense was more than offset by an increase in our interest capitalized. Gross interest expense increased to $260 million in 2015 from $114 million in 2014 due to our increased borrowing level related to financing the acquisition of our Southwest Appalachia assets and a $47 million charge for unamortized fees associated with the repayment of our bridge facility in January 2015. Interest capitalized increased to $204 million in 2015, compared to $55 million in 2014 as the result of the increase in our unevaluated property balance associated with the 2014 acquisition of our Southwest Appalachia assets.

Interest expense, net of capitalization, was $59 million in 2014. The increase of $17 million compared to 2013 is primarily due to our increased borrowing level. Interest capitalized was $55 million in 2014 as compared to $62 million in 2013.

Gain (Loss) on Derivatives

In general, our basis swaps, certain fixed price swaps, fixed price call options and interest rate swaps are not designated for hedge accounting treatment. Changes in the fair value of derivatives that are not designated as cash flow hedges are recorded in gain (loss) on derivatives. For those instruments not designated for hedge accounting, we recorded a gain of $44

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million related to fixed price swaps, a gain of $13 million related to fixed price call options, a loss of $4 million related to basis swaps and a loss of $6 million related to interest rate swaps for the year ended December 31, 2015.

Income Taxes

Our effective tax rate was 31%, 36%, and 41%, in 2015, 2014 and 2013, respectively. Our effective tax rate decreased in 2015 as compared to 2014 primarily due to an increase in our deferred tax asset valuation allowance. Our effective tax rate decreased in 2014 as compared to 2013 primarily due to a redetermination of the deferred state tax liability to reflect updated state apportionment factors in certain states. In general, differences between our effective tax rate and the federal tax rate of 35% primarily result from the effect of certain state income taxes and permanent items attributable to book-tax differences. We refer you to Note 10 to the consolidated financial statements for additional discussion about our income taxes.

Reconciliation of Non-GAAP Measures

We report our financial results in accordance with GAAP. However, management believes certain non-GAAP performance measures may provide users of this financial information additional meaningful comparisons between current results and the results of our peers and of prior periods.

We define Adjusted EBITDA as net income plus interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties, (gain) loss on derivatives, excluding derivatives, settled, gain on sale of assets and certain one-time charges. Management presents measures such as Adjusted EBITDA because it is used by many investors and it is a financial measure commonly used in the energy industry. Adjusted EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with GAAP, or as a measure of the company's profitability or liquidity. Adjusted EBITDA as defined above may not be comparable to similarly titled measures of other companies. The table below reconciles Adjusted EBITDA, as defined, with net income.

	E&P	Midstream Services	Other	Total
2015	(in millions)			
Net income (loss) attributable to common stock	$ (4,848)	$ 297	$ (111)	$ (4,662)

Mandatory convertible preferred stock dividend	–	–	106	106
Net income (loss)	$ (4,848)	$ 297	$ (5)	$ (4,556)
Add back (deduct):				
Depreciation, depletion and amortization expense	1,028	62	1	1,091
Impairment of natural gas and oil properties	6,950	–	–	6,950
Gain on sale of asset	(6)	(277)	–	(283)
Write-down of inventory	23	9	–	32
Loss on derivatives excluding derivatives, settled	155	–	–	155
Net interest expense	47	9	–	56
Provision (benefit) for income taxes	(2,273)	268	–	(2,005)
Adjusted EBITDA	$ 1,076	$ 368	$ (4)	$ 1,440
2014				
Net income (loss)	$ 704	$ 224	$ (4)	$ 924
Add back (deduct):				
Depreciation, depletion and amortization expense	884	58	–	942
(Gain) loss on derivatives excluding derivatives, settled	(131)	1	–	(130)
Net interest expense	47	12	–	59
Provision for income taxes	402	123	–	525
Adjusted EBITDA	$ 1,906	$ 418	$ (4)	$ 2,320
2013				
Net income (loss)	$ 509	$ 196	$ (1)	$ 704
Add back (deduct):				
Depreciation, depletion and amortization expense	735	51	1	787
Gain on derivatives excluding derivatives, settled	(21)	–	–	(21)
Net interest expense	30	11	1	42
Provision (benefit) for income taxes	368	119	(1)	486
Adjusted EBITDA	$ 1,621	$ 377	$ –	$ 1,998

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LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally generated funds, our $2.0 billion revolving credit facility and funds accessed through term loans such as our $750 million term loan facility and capital markets as our primary sources of liquidity.

In 2016, we expect to have decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the low commodity price environment. Accordingly, we anticipate adjusting our activity levels and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. Although our 2016 capital investment program is expected to be funded through cash flow from operations, we have the financial flexibility to draw on a portion of the funds available under our revolving credit facility to fund the portion of our planned capital investments exceeding our operating cash flow as necessary (discussed below under “Capital Investments”). We refer you to Note 8 of the consolidated financial statements included in this Annual Report and the section below under “Financing Requirements” for additional discussion of our revolving credit facility and commercial paper program.

As of December 31, 2015, our capital structure consisted of 67% debt and 33% equity. We believe that our operating cash flow and available funds under our revolving credit facility will be adequate to meet our capital and operating requirements for 2016. If we do not have adequate liquidity or are unable to obtain financing on favorable terms or at all, however, we may not be able to make intended capital investments, which could restrict our ability to grow and could have a material adverse effect on our results of operations, cash flows and financial condition. Additionally, our ability to make payments on and to refinance our indebtedness will depend on our ability to generate cash in the future. See “Risk Factors – Lower commodity prices may impair our ability to service our existing debt or refinance it when it becomes due.” The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet our obligation. We refer you to the section below under “Financing Requirements” for additional discussion of our compliance with the covenants of our revolving credit and term loan facilities.

Net cash provided by operating activities decreased 32% to $1.6 billion in 2015, due to a decrease in net income adjusted for non-cash expenses and changes in working capital accounts. Net cash provided by operating activities increased 22% to $2.3 billion in 2014 over 2013 due to an increase in net income adjusted for non-cash expenses and changes in working capital accounts. For 2015, requirements for our capital investments were funded primarily from our cash generated by operating activities, net proceeds from borrowings under our revolving credit facility, commercial paper, term loan agreement and cash and cash equivalents. Net cash from operating activities provided 66% of our cash requirements for capital investments, including acquisitions, in 2015, 31% in 2014 and 85% in 2013.

Our cash flow from operating activities is highly dependent upon the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See “Risk Factors” in Item 1A, “Quantitative and Qualitative Disclosures about Market Risks” in Item 7A and Note 5, “Derivatives and Risk Management” in the consolidated financial statements for further details. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and co-owners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and co-owners could adversely impact our cash flows.

Due to these above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow. Further, we may from time to time seek to retire or rearrange some or all of our outstanding debt or preferred stock through cash purchases, retirements, new issuances, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, could be material and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors.

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Capital Investments

Our capital investments were $2.4 billion in 2015 compared to $7.4 billion in 2014 and $2.2 billion in 2013. Capital investments include a decrease of $33 million in 2015, an increase of $155 million in 2014 and a decrease of $25 million in 2013 related to the change in accrued expenditures between years. Our E&P segment investments in 2015 were $2.3 billion, which included $533 million, in total, relating to the acquisitions from WPX Energy, Inc. ("WPX") and Statoil ASA ("Statoil"), compared to $7.3 billion in 2014, which included $5.2 billion primarily related to the Chesapeake Property Acquisition, and $2.1 billion in 2013, which included $96 million primarily related to the acquisition of properties in Northeast Appalachia. Our Midstream Services capital investments for 2015 included $109 million related to the acquisition from WPX.

	Capital investments for the years ended December 31,		
	2015	2014	2013
		(in millions)	
Exploration and production	$ 1,725	$ 2,021	$ 1,956
Acquisitions	642	5,233	96
Midstream Services	58	144	158
Other	12	49	25
	$ 2,437	$ 7,447	$ 2,235

In 2016, we expect to have decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the lower commodity price environment. We anticipate adjusting our activity levels throughout our portfolio and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. Although our 2016 capital investment program is expected to be funded through cash flow from operations, we have the financial flexibility to utilize borrowings under our revolving credit facility and our commercial paper program as necessary.

Financing Requirements

Our total debt outstanding was $4.7 billion as of December 31, 2015, compared to $7.0 billion at December 31, 2014.

In November 2015, we entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was used to repay borrowings under the revolving credit facility. The interest rate on the term loan facility is determined based upon our public debt ratings from S&P and Moody's and was 137.5 basis points over the London Interbank Offered Rate ("LIBOR") as of December 31, 2015. In February 2016, S&P and Moody's downgraded our ratings to BB+ and B1, respectively, increasing our interest rate on the term loan to 162.5 basis points over LIBOR. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business.

In April 2015, we entered into a commercial paper program which allowed us to issue up to $2.0 billion in commercial paper, provided that outstanding borrowings from our commercial paper program, combined with outstanding borrowings under our revolving credit facility, not exceed $2.0 billion. The commercial paper issuance had terms of up to 397 days and carried interest at rates agreed upon at the time of each issuance. As of December 31, 2015, we had no outstanding issuances under our commercial paper program and have no plans of utilizing the commercial paper market after the first quarter of 2016.

In January 2015, we completed concurrent underwritten public offerings of 30,000,000 shares of 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 expenses. Each depositary share represents a 1/20th interest in a share of our 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 a $4.5 billion 364-day bridge facility that we entered into in December 2014 in connection with our acquisition of assets in Southwest Appalachia, with the remaining balance fully repaid with proceeds from our January 2015 public offering of $2.2 billion in senior notes.

The mandatory convertible preferred stock entitles the holders to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Dividends are to be paid at a rate of 6.25% per annum on the liquidation preference of $1,000 per share and can be paid in cash, common stock or a combination of both. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of our common stock (and, correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of our common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of our common stock over a 20 trading-day period immediately prior to that date.

Our mandatory convertible preferred stock has the non-forfeitable right to participate on an as converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. As such, it is included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings.

In January 2015, we completed a public offering of $350 million aggregate principal amount of our 3.30% senior notes due 2018 (the "2018 Notes"), $850 million aggregate principal amount of our 4.05% senior notes due 2020 (the "2020 Notes") and $1.0 billion aggregate principal amount of our 4.95% senior notes due 2025 (the "2025 Notes" and together with the 2018 and 2020 Notes, the "Notes"), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The proceeds from the sale of the Notes were used to repay all principal and interest remaining outstanding under our $4.5 billion 364-day bridge facility, which was first reduced with proceeds from our concurrent underwritten public offerings of common stock and depositary shares. Proceeds from the sale of the Notes were also used to repay a portion of amounts outstanding under our revolving credit facility. 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 interest rates on the Notes is determined based upon our public debt ratings from S&P and Moody's. Downgrades from either rating agency increase our interest costs by 25.0 basis points per downgrade level on the following semi-annual bond interest payment. Based on the February 2016 downgrades from S&P and Moody's our interest rates on these notes will increase by 125.0 basis points effective July 2016.

In December 2014, we entered into a $500 million unsecured two-year term loan credit agreement with various lenders. The term loan facility required prepayments under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business or for specified uses and was repaid in full in April 2015 principally with proceeds from the divestiture of our northeast Pennsylvania gathering assets and borrowings under our revolving credit facility.

In December 2013, we entered into a credit agreement that exchanged our previous revolving credit facility. Under the revolving credit and facility, we have a borrowing capacity of $2.0 billion. Our current revolving credit facility has a maturity date of December 2018 and options for two one-year extensions with participating lender approval. The amount available under the revolving credit facility may be increased by $500 million upon our agreement with our participating lenders. The interest rate on the revolving credit facility is determined based upon our public debt ratings from S&P and Moody's and was 150.0 basis points over LIBOR as of December 31, 2015. Based on the February 2016 downgrades from S&P and Moody's our interest rate increased to 200.0 basis points over LIBOR. The revolving credit facility is unsecured and is not guaranteed by any of our subsidiaries. Contemporaneously with the execution of the credit agreement, in December 2013, we obtained releases of subsidiary guarantees under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% senior notes.

Our revolving credit and term loan facilities contain covenants that impose certain restrictions on us. Under our revolving credit and term loan facilities we must keep our total debt at or below 60% of our total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any non-cash impacts from any full cost ceiling impairments, certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our revolving credit and term loan facilities, our adjusted capital structure as of December 31, 2015 was 38% debt and 62% equity. We were in compliance with all of the covenants of our revolving credit and term loan facilities as of December 31, 2015. Although we do not anticipate any violations of our financial covenants, our ability to comply with these covenants are dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our revolving credit facility, we may have to decrease our capital investment plans.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At February 23, 2016, we had NYMEX commodity price hedges in place on 37 Bcf of our targeted 2016 natural gas production. The amount of long-term debt we incur will be largely dependent upon commodity prices and our capital investment plans.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2015, our material off-balance sheet arrangements and transactions include operating lease arrangements. There are no other transactions, arrangements or other relationships with unconsolidated entities or other

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persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to "Contractual Obligations and Contingent Liabilities and Commitments" below.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations as of December 31, 2015, were as follows:

Contractual Obligations:

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
	(in millions)				
Transportation charges(1)	$ 8,881	$ 623	$ 1,403	$ 1,453	$ 5,402
Debt	4,733	1	1,882	850	2,000
Interest on debt(2)	1,091	202	372	233	284
Operating leases(3)	275	71	108	68	28
Compression services(4)	49	21	22	6	–
Operating agreements	10	10	–	–	–
Purchase obligations	2	2	–	–	–
Other obligations(5)	602	31	35	14	522
	$ 15,643	$ 961	$ 3,822	$ 2,624	$ 8,236

(1)As of December 31, 2015, we had commitments for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems. Of the total $8.9 billion, 38% related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. Additionally, $100 million relates to demand charges under firm transportation agreements under which we have the option to reduce our commitment by 531 Bcf beginning in 2018.

(2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2015. Interest payments on the revolving credit facility were calculated by assuming that the December 31, 2015 outstanding balance of $116 million will be outstanding through the December 2018 maturity date. Interest payments on the term loan facility were calculated by assuming that the December 31, 2015 outstanding balance of $750 million will be outstanding through the December 2018 maturity date. A constant rate of 1.886% and 1.775%, the rate as of December 31, 2015, was assumed for the revolving credit facility and term loan facility, respectively. All interest rates were based on our credit ratings as of December 31, 2015.

(3)Operating leases include costs for compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2027.

(4)As of December 31, 2015, our Midstream Services segment had commitments of approximately $42 million and our E&P segment had commitments of approximately $7 million for compression services associated primarily with our Fayetteville and Southwest Appalachia divisions.

(5)Our other significant contractual obligations include approximately $572 million for asset retirement obligations primarily relating to natural gas and oil properties and approximately $14 million for various information technology support and data subscription agreements.

Liabilities relating to uncertain tax positions are excluded from the table above as there is a high degree of uncertainty regarding the timing of future cash outflows related to such liabilities. Also excluded from the table above are future contributions to the pension and postretirement benefit plans. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 12 to the consolidated financial statements and "Critical Accounting Policies and Estimates" below for additional information.

We refer you to Note 8 to the consolidated financial statements for a discussion of the terms of our debt.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described in "Financing Requirements" above. We had negative working capital of $0.3 billion as of December 31, 2015 and negative working capital of $4.3 billion at December 31, 2014. The negative working capital as of December 31, 2015 was primarily due to a decrease in derivative assets in 2015. The negative working capital as of December 31, 2014 was driven by the outstanding balance on our bridge facility, which was repaid in full in January 2015.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We evaluate our estimates on an on-going basis, based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following describes significant judgments and estimates used in the preparation of our consolidated financial statements.

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.59 per MMBtu, West Texas Intermediate oil of $46.79 per barrel, and NGLs of $6.82 per barrel, adjusted for market differentials, the net book value of our United States natural gas and oil properties exceeded the ceiling by $1,586 million (net of tax) at December 31, 2015 and resulted in a non-cash ceiling test impairment. No cash flow hedges were in place as of December 31, 2015. In the second and third quarters of 2015, the net book value of our United States natural gas and oil properties exceeded the ceiling by $944 million (net of tax) at June 30, 2015 and $1,746 million (net of tax) at September 30, 2015, respectively, and resulted in non-cash ceiling test impairments. Cash flow hedges of natural gas production in place increased the ceiling amount by approximately $60 million and $40 million as of June 30, 2015 and September 30, 2015, respectively. At December 31, 2014, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months of $4.35 per MMBtu for Henry Hub natural gas, West Texas Intermediate oil of $91.48 per barrel, and NGLs of $23.79 per barrel. At December 31, 2013, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.67 per MMBtu, for West Texas Intermediate oil of $93.42 and for NGLs of $43.45 per barrel. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the first quarter of 2016 ranging from approximately $300 million to $500 million, net of tax, when excluding future changes in costs excluded from amortization, with likely material impairments continuing beyond the first quarter.

A decline in natural gas, oil and NGL prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves. Our reserve base as of December 31, 2015 is approximately 95% natural gas compared to 91% as of December 31, 2014. In the past, nearly all of our reserve base has been natural gas, therefore changes in oil and NGL prices used did not have as significant an impact as natural gas prices on cash flows and reserve quantities. Our standardized measure and reserve quantities as of December 31, 2015, were $2.4 billion and 6.2 Tcfe, respectively.

Natural gas, oil and NGL reserves cannot be measured exactly. Our estimate of natural gas, oil and NGL reserves requires extensive judgments of reservoir engineering data and projections of cost that will be incurred in developing and producing reserves and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team to which the property is assigned. The reservoir engineering and financial data included in these estimates are reviewed by senior engineers who are not part of the asset management teams and by our Reservoir Supervisor - Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Reservoir Supervisor – Reserves has more than 29 years of experience in petroleum engineering, including the estimation of oil and natural gas reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2009, our Reservoir Supervisor - Reserves served in various reservoir engineering roles for Citation Oil & Gas Corporation, Mitchell Energy & Development Corporation, Whites Stone

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Energy and H.J. Gruy & Associates, is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers and is a Licensed Professional Engineer in the state of Texas. He reports to our Vice President and General Manager – Strategy, Performance and Innovation who has more than 29 years of experience in reservoir engineering including the estimation of natural gas, oil and NGL reserves in multiple basins in the United States. Prior to joining Southwestern in 1993, our Vice President and General Manager – Strategy, Performance and Innovation served in various engineering roles for Conoco Inc and is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, American Institute of Professional Geologists, IPAA and TIPRO. He is also a Licensed Professional Engineer in the state of Texas. On our behalf, the Vice President and General Manager – Strategy, Performance and Innovation engages NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the two technical persons primarily responsible for auditing our proved reserves estimates (1) have over 33 years and over 13 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 23 years and over 13 years of experience in the estimation and evaluation of reserves, respectively; (3) each has a college degree; (4) each is a Licensed Professional Geoscientist in the State of Texas or a Licensed Professional Engineer in the State of Texas; (5) each meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; and (6) each is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The financial data included in the reserve estimates is also separately reviewed by our accounting staff. Our proved reserves estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors with whom final authority over the estimates of our proved reserves rests. A copy of NSAI's report has been filed as Exhibit 99.1 to this Annual Report.

Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves accounted for 93% of our total reserve base as of December 31, 2015. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to “Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated” in Item 1A, “Risk Factors,” of Part I of this Annual Report for a more detailed discussion of these uncertainties, risks and other factors.

In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI’s audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 100% of the present worth of the company’s total proved reserves.

NSAI's audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The properties in the bottom 20% of the total present worth are typically not reviewed in the audit. The fields included in approximately the top 100% present value as of December 31, 2015, accounted for approximately 99% of our total proved reserves and approximately 100% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data we provided to them with respect to ownership interests, natural gas, oil and NGL production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. On January 15, 2016, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2015, stating that our estimated proved natural gas, oil and NGL reserves are, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Business Combinations

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved natural gas and oil properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of reserves, future operating and development costs, future commodity prices and a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and natural gas properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties. Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities.

In January 2015, we completed acquisitions of certain natural gas and oil assets from WPX Energy, Inc. (the “WPX Property Acquisition”) and Statoil ASA (the “Statoil Property Acquisition”). These acquisitions qualified as business combinations and as such, we estimated the fair value of the assets acquired and liabilities assumed as of the January 2015 acquisition dates. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. We used discounted cash flow models and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as defined in Note 7 of our consolidated financial statements. We recorded the assets acquired and liabilities assumed in the WPX Property Acquisition and the Statoil Property Acquisition at their estimated fair values of approximately $270 million and $357 million, respectively, which we consider to be representative of the prices paid by typical market participants. These measurements resulted in no goodwill or bargain purchases being recognized.

The 2014 Chesapeake Property Acquisition qualified as a business combination, and as such, we estimated the fair value of the assets acquired and liabilities assumed as of the December 22, 2014 acquisition date. We recorded the assets acquired and liabilities assumed in the Chesapeake Property Acquisition at their estimated fair value of approximately $5.0 billion, which we consider to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized.

Hedging

We use natural gas agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In 2015, 2014, and 2013 we hedged 27%, 60% and 44% of our natural gas production, respectively. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is generally offset by the gain or loss recognized upon the related natural gas transaction that is hedged.

Our derivative instruments are recorded at fair value in our consolidated financial statements and generally qualify for hedge accounting. We have established the fair value of derivative instruments using data provided by our counterparties in conjunction with assumptions evaluated internally using established index prices and other sources. These valuations are recognized as assets or liabilities on our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production, the offset is recorded in other comprehensive income. Results of settled commodity derivative transactions that qualify for hedge accounting are reflected in gas sales. Any derivative not designated for hedge accounting treatment or any ineffective portion of a properly designated hedge is recognized immediately in earnings. As of December 31, 2015, our fixed price basis swaps and fixed price call options were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the year ended December 31, 2015, we recorded a gain on derivatives of $44 million related to fixed price swaps not designated for hedge accounting, a gain on derivatives of $13 million related to fixed price call options that were not designated for hedge accounting treatment and a loss on derivatives of $4 million related to the basis swaps that were not designated for hedge account treatment. Also recorded in gain (loss) on derivatives at December 31, 2015 was a loss of $6 million related to our interest rate swap.

Future market price volatility could create significant changes to the hedge positions recorded in our consolidated financial statements. We refer you to “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A of Part II of this Annual Report for additional information regarding our hedging activities.

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Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 12 to the consolidated financial statements for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2015 benefit obligation and periodic benefit cost to be recorded in 2016, the discount rate assumed is 4.60% and 4.25%, respectively. This compares to a discount rate of 4.25% and 5.00% for the benefit obligation and periodic benefit cost recorded in 2015, respectively. For the 2016 periodic benefit cost, the expected return assumed is 7.00%, compared to an expected return of 7.00% in 2015.

Using the assumed rates discussed above, we recorded total benefit cost of $19 million in 2015 related to our pension and other postretirement benefit plans. Due to the significance of the discount rate and expected long-term rate of return, the following sensitivity analysis demonstrates the effect that a 50 basis point change in those assumptions would have had on our 2015 pension expense:

	Increase (Decrease) of Annual Pension Expense	
	50 Basis Point Increase	50 Basis Point Decrease
	(in millions)	
Discount rate	$ (1)	$ 1
Expected long-term rate of return	$ (1)	$ 1

As of December 31, 2015, we recognized a liability of $50 million, compared to $44 million at December 31, 2014, related to our pension and other postretirement benefit plans. During 2015, we also made cash payments totaling $12 million to fund our pension and other postretirement benefit plans.

Asset Retirement Obligations

We own natural gas and oil properties, which require expenditures to plug and abandon the wells when reserves in the wells are depleted. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The recognition of asset retirement obligations requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate, all of which are subject to change.

Stock-Based Compensation

We account for stock-based compensation transactions using a fair value method and recognize an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalize the cost into natural gas and oil properties or gathering systems included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of our natural gas and oil properties or directly related to the construction of our gathering systems. We use models to determine fair value of stock-based compensation, which requires significant judgment with respect to forfeitures, volatility and other factors. If any of the assumptions change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period.

New Accounting Standards Implemented in this Report

Refer to Note 1 to the consolidated financial statements of this Annual Report for further discussion of our significant accounting policies and for discussion of accounting standards implemented.

New Accounting Standards Not Yet Implemented in this Report

Refer to Note 1 to the consolidated financial statements of this Annual Report for further discussion of our significant accounting policies and for discussion of accounting standards not yet implemented.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Annual Report on Form 10-K identified by words such as “anticipate,” “intend,” “plan,” “project,” “estimate,” “continue,” “potential,” “should,” “could,” “may,” “will,” “objecti “outlook,” “effort,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “forecast,” “target” or similar words.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

* the timing and extent of changes in market conditions and prices for natural gas, oil and NGLs (including regional basis differentials);
* our ability to fund our planned capital investments;
* a change in our credit rating;
* the extent to which lower commodity prices impact our ability to service or refinance our existing debt;
* the impact of volatility in the financial markets or other global economic factors;
* difficulties in appropriately allocating capital and resources among our strategic opportunities;
* t