NEWFIELD EXPLORATION CO /DE/
Form 10-K
February 21, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission file number: 1-12534
Newfield Exploration Company
(Exact name of registrant as specified in its charter)

Delaware	72-1133047
(State of incorporation)	(I.R.S. Employer Identification No.)
4 Waterway Square Place, Suite 100, The Woodlands, Texas	77380 (Zip Code)
(Address of principal executive offices)	

Registrant's telephone number, including area code:
(281) 210-5100
Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No þ
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 þ 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) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of the 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. (Check one):
Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
(Do not check if a 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 þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $8.7 billion as of June 30, 2016 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of February 16, 2017, there were 198,963,323 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Portions of the Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 16, 2017, which is incorporated by reference to the extent specified in Part III of this Form 10-K.

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If you are not familiar with any of the oil and gas terms used in this report, we have provided explanations of many of them under the caption "Commonly Used Oil and Gas Terms" at the end of Items 1 and 2 of this report. Unless the context otherwise requires, all references in this report to "Newfield," "we," "us," "our" or the "Company" are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest.

Forward-Looking Information

This report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). All statements, other than statements of historical facts included in this report, are forward-looking, including information relating to anticipated future events or results, such as planned capital expenditures, the availability and sources of capital resources to fund capital expenditures, estimates of reserves, projected production, estimates of operating costs, acquisitions and divestitures, planned exploratory or developed drilling, projected cash flows and liquidity, business strategy and other plans and objectives for future operations. Forward-looking statements are typically identified by use of terms such as "may," "believe," "expect," "anticipate," "intend," "estimate," "project," "target," "goal," "plan," "should," "will," "predict," "potential" and similar expressions that convey the uncertainty of future events or outcomes. Although we believe that the expectations reflected in such forward-looking statements are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, including but not limited to, the following:

- oil, natural gas and natural gas liquids prices;
- actions of the Organization of the Petroleum Exporting Countries (OPEC), its members and other state-controlled oil companies relating to oil price and production controls;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- legislation or regulatory initiatives intended to address seismic activity;
- the timing and our success in discovering, producing and estimating reserves;
- sustained decline in commodity prices resulting in impairments of assets;
- ability to develop existing reserves or acquire new reserves;
- the availability and volatility of the securities, capital or credit markets and the cost of capital;
- maintaining sufficient liquidity to fund our operations and business strategies;
- the accuracy of and fluctuations in our reserves estimates due to sustained low commodity prices, incorrect assumptions and other causes;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- general economic, financial, industry or business trends or conditions;
- the impact of, and changes in, legislation, law and governmental regulations, including those related to hydraulic fracturing, climate change and over-the-counter derivatives;
- land, legal, regulatory, and ownership complexities inherent in the U.S. and Chinese oil and gas industries;
- the impact of regulatory approvals;
- the ability and willingness of current or potential lenders, derivative contract counterparties, customers and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us, including the creditworthiness of such counterparties;

- the prices and quantities of commodities reflected in our commodity derivative arrangements as compared to the actual prices or quantities of commodities we produce or use;
- the volatility, instrument terms and liquidity in the commodity futures and commodity and financial derivatives markets;
- drilling risks and results;
- the prices and availability of goods and services;
- the cost and availability of drilling rigs and other oilfield services;
- global events that may impact our domestic and international operating contracts, markets and prices;
- our ability to monetize non-strategic assets, repay or refinance our existing indebtedness and the impact of changes in our investment ratings;
- labor conditions;
- weather conditions;
- competitive conditions;
- terrorism or civil or political unrest in a region or country;
- electronic, cyber or physical security breaches;
- changes in tax rates;
- inflation rates;
- the effect of worldwide energy conservation measures;
- the price and availability of, and demand for, competing energy sources;
- our ability to successfully execute our business and financial plans and strategies;
- the availability (or lack thereof) of acquisition, disposition or combination opportunities; and
- the other factors affecting our business described under the caption "Risk Factors" and "Management’s Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates."

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

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. See Items 1 and 2, "Business and Properties," Item 1A, "Risk Factors," Item 3, "Legal Proceedings," Item 7, "Management’s Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" for additional information about factors that may affect our business and operating results. These factors are not necessarily all of the important factors that could affect us. Use caution and common sense when considering these forward-looking statements. Unless securities laws require us to do so, we do not undertake any obligation to publicly correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

PART I

Items 1 and 2. Business and Properties

General

Newfield Exploration is an independent exploration and production company with estimated consolidated proved reserves of approximately 513 million barrels of oil equivalent. Substantially all proved reserves and approximately 90% of our daily production are located onshore in the United States. We are a Delaware corporation, incorporated in 1988 and publicly traded on the New York Stock Exchange (NYSE) since 1993. We have been a member of the S&P 500 Index since 2010. Our U.S. operations are onshore and focus primarily on large scale, liquids-rich resource plays. Our principal areas of operation are the Anadarko and Arkoma basins of Oklahoma, the Williston Basin of North Dakota and the Uinta Basin of Utah. In addition, we have oil producing assets offshore China.

Newfield has undergone a significant transformation over the last decade. We have transitioned from a diversified asset base of onshore, offshore and international operations to a more focused portfolio of domestic onshore liquids-rich resource plays with an extensive inventory of drilling opportunities. Furthermore, we have shifted our proved reserves and production from largely natural gas to a greater percentage of oil and natural gas liquids. Our corporate vision is clear: to be recognized as the premier independent E&P company delivering operational excellence, top-tier business results and value to our shareholders, employees and the communities in which we live and work.

2016 Executive Summary

- Invested $749 million (excluding acquisitions) primarily in our highest return plays, SCOOP and STACK, located in the Anadarko Basin of Oklahoma;

- Increased 2016 domestic production by 7% over 2015 to 54.2[(1)] MMBOE;

- Lowered our average domestic lease operating expenses 24%, on a per barrel basis, during 2016;

- Added proved reserves during 2016 through extensions, discoveries and revisions of 63 MMBOE. Total Company PV-10[(2)] decreased 9% to $2.7 billion versus the prior year end mainly due to lower commodity prices. At year-end 2016, approximately 61% of consolidated reserves were proved developed;

- Year-end 2016 estimated proved reserves were 513 MMBOE, of which approximately 99% are located onshore in the United States (total domestic reserves are approximately 36% oil, 19% NGLs and 45% natural gas);

- The Company has a nine-year reserve life index (based on 2016 production levels);

- Acquired additional properties in the Anadarko Basin STACK play for an adjusted purchase price of $476 million, which included approximately 40,000 net undeveloped acres;

- The Anadarko Basin is our largest producing region and contains our greatest concentration of reserves, averaging production of approximately 88 MBOEPD net in the fourth quarter of 2016. At year-end 2016, the Anadarko Basin comprised 64% of our total proved reserves and 65% of current domestic production. We finished 2016 with interests in approximately 400,000 net acres in the Anadarko Basin;

- Divested substantially all our oil and gas assets in the Maverick and Gulf Coast basins of Texas for approximately $380 million;

- Reduced our overall workforce in 2016 by more than 15% primarily through the closure and consolidation of our Tulsa regional office into our headquarters in The Woodlands, Texas;

- Issued 34.5 million additional shares of common stock through a public equity offering in the first quarter of 2016 for net proceeds of approximately $776 million. A portion of the proceeds was used to acquire additional properties in STACK and to repay borrowings under our revolving credit facility and money market lines of credit. The remainder is available for general corporate purposes;

- Realized $201 million in derivative gains during 2016;
- At year-end 2016, we had $555 million of cash and cash equivalents on our consolidated balance sheet and had no borrowings outstanding under our revolving credit facility; and
- Our China liftings for 2016 were 5.4 MMBbls.

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(1) Includes 5.3 Bcf of natural gas produced and consumed in operations.

(2) PV-10 is a non-GAAP financial measure and generally differs from the standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented under U.S. generally accepted accounting principles) because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor the standardized measure represents an estimate of the fair market value of our crude oil and natural gas properties. PV-10 is used in the oil and natural gas industry as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific income tax characteristics of such entities. The following table shows a reconciliation of the standardized measure to PV-10:

	Domestic	China	Total
	(In millions)		
December 31, 2016:			
Standardized measure of discounted future net cash flows	$2,520	$64	$2,584
Present value of future income tax expense	101	—	101
Proved reserve PV-10 value (before tax)	$2,621	$64	$2,685
December 31, 2015:			
Standardized measure of discounted future net cash flows	$2,554	$222	$2,776
Present value of future income tax expense	164	—	164
Proved reserve PV-10 value (before tax)	$2,718	$222	$2,940

2017 Outlook

Our industry has been significantly impacted by lower crude oil and natural gas prices since late 2014. Following a five-year period (2010-2014) of unprecedented strength and consistency, oil prices collapsed in late 2014. Prices averaged approximately $49 per barrel (NYMEX WTI) in 2015 and $43 per barrel in 2016. During this period of commodity price uncertainty, we adapted our near-term business strategies to preserve liquidity and financial strength.

Although Newfield and other domestic producers curtailed capital investments in both 2015 and 2016, and many long-lead development projects around the world were slowed or canceled, the global oil market remains oversupplied. The outlook for oil prices in 2017 has improved following recent OPEC actions to curtail supply. As of February 16, 2017, NYMEX WTI was $53.36 per barrel, and the three-year forward curve averaged $54.44 per barrel. Domestic natural gas prices also improved slightly. As of February 16, 2017, NYMEX Henry Hub was $2.85 per MMBtu, and the three-year forward curve averaged $2.99 per MMBtu.

Our 2017 capital investment plan is approximately $1.0 billion (excluding approximately $120 million of expected capitalized interest and direct internal costs), an increase of approximately 40% over 2016 capital investment levels. We expect to fund our 2017 investments through cash flows from operations and cash on hand. Should commodity prices weaken, we may elect to curtail our investments to limit borrowings and preserve liquidity.

Our primary near-term focus includes:

- preserve liquidity and financial strength;
- focus on organic opportunities through disciplined capital investments;

- high-grade investments based on rates of return;

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- improve operational efficiencies and economic returns;
- execute select, strategic acquisitions and divestitures; and
- attract and retain quality employees who are aligned with stockholders' interests.

Our 2017 domestic production is expected to be approximately 52.5 MMBOE, down 3% when compared to our 2016 production of 54.2 MMBOE. Our 2016 domestic production included 3.4 MMBOE from our Texas assets that were sold in September 2016. Consolidated production in 2017 is expected to be 54.7 MMBOE, down 8% when compared to our 2016 production of 59.6 MMBOE. The decrease is attributable to the impact of the 2016 Texas assets sale, natural declines in our China producing assets and our recently announced agreement to sell our non-operated interest in Bohai Bay in China.
Our estimated 2017 domestic production by area and domestic capital expenditure budget follows:

In 2017, we will transition to full-field development in the Anadarko Basin and expect to allocate approximately 85% of our capital investments to the SCOOP and STACK plays. These plays currently provide some of the highest returns in our portfolio, which we anticipate enhancing through additional operational efficiencies expected to be gained with the move to development-driven activity.

Our Business Strategy

Our efforts to refine our asset base and better focus our investments on oil and liquids-rich onshore resource plays in the U.S. are consistent with our long-term business strategy of creating lasting stockholder value through the consistent growth of cash flow, production and proved reserves. Today, our primary growth area is the Anadarko Basin of Oklahoma where we have an extensive inventory of drilling locations. SCOOP and STACK are characterized by wells with strong production rates, high initial oil cuts and low operating expenses.

Our business strategy includes the following:

Preserving financial strength. Maintaining a strong balance sheet and liquidity remains central to our business strategy. For 2017, our goals will be to combine profitable growth and financial flexibility through strong credit metrics and ample liquidity as we seek to manage future uncertainties in both oil and gas prices. Our capital program is adaptable and frequently adjusted to reflect fluctuations in commodity markets. Over the last several years, we have divested non-strategic assets and used derivatives to protect a portion of our future production from commodity price volatility to ensure adequate funds were available to execute our drilling programs.

Focusing on organic opportunities through disciplined capital investments. While we consider various growth opportunities, including strategic acquisitions, our primary focus is on organic growth. Our capital program is primarily designed to allocate investments based on projects that maximize our production and reserve growth at attractive returns.

High-grade investments based on rate of return. In line with this element of our strategy and the commodity price environment, approximately 85% of our 2017 capital investments will be focused on SCOOP and STACK. The Anadarko Basin has a deep inventory of product-diverse drilling locations with high rates of returns, which have proven to have commodity price-resiliency over the past several years. As we move to more development-driven activity, we expect to continue to see improvements in operational efficiencies in 2017.

Continuously improving operations and returns. Controlling the costs to find, develop and produce oil, natural gas and NGLs is critical to creating long-term stockholder value. Our focus areas are characterized by large, contiguous acreage positions and multiple stacked geologic horizons. In 2016, we reduced our average well costs in every area through faster drilling times and innovative completion optimizations. In addition, reductions in service costs have positively impacted our business. These savings have been used to test upsized completions to enhance returns and estimated ultimate recoveries. We also have multiple initiatives underway to manage our base production, improve operational efficiencies and enhance future margins.

Executing select, strategic acquisitions and divestitures. We target complementary acquisitions in existing core areas and focus on acquisition opportunities where our operating and technical knowledge is transferable and drilling results can be forecast with confidence. In 2016, we acquired additional properties in the Anadarko Basin STACK play for an adjusted purchase price of $476 million, subject to customary post-close adjustments. In addition, from 2011 through 2016, we divested approximately $3.0 billion of non-strategic assets, including the sale of our Texas assets for approximately $380 million in September 2016, and used the proceeds to fund drilling, acquire additional acreage and reduce borrowings.

Attracting and retaining quality employees who are aligned with stockholder interests. We believe in hiring top-tier talent and are committed to our employees' career development. We believe that employees should be rewarded based on their performance and that their interests should be aligned with those of our stockholders. As a result, we reward and encourage our employees through performance-based annual compensation and long-term equity-based incentives.

Description of Properties

Our U.S. operations are onshore and focus primarily on large scale, liquids-rich resource plays. Our domestic plays represent substantially all of our estimated consolidated proved reserves at year-end 2016. The remaining 1% of our proved reserves at year-end 2016 is attributable to our offshore producing assets in China.

Anadarko Basin. SCOOP and STACK have been our fastest growing plays over the last several years. At year-end 2016, the Anadarko Basin represented approximately two-thirds of our consolidated proved reserves and daily domestic production. After recent additions and acquisitions, we held approximately 400,000 net acres in SCOOP and STACK at year-end 2016. Our average net production from the basin in the fourth quarter of 2016 was approximately 88 MBOEPD (34% oil and 27% NGLs), an increase of 18% compared to the fourth quarter of 2015.

Arkoma Basin. We have significant dry gas production in the Arkoma Basin, representing approximately 12% of our total consolidated proved reserves at year-end 2016. Our investment levels in this area have been significantly curtailed in recent years due to low natural gas prices. As of December 31, 2016, we had approximately 147,000 net acres in the Arkoma Basin, and our net production for the fourth quarter of 2016 was approximately 16 MBOEPD (98% dry gas).

Uinta Basin. We have approximately 217,000 net acres in the Uinta Basin, which represents about 13% of our consolidated proved reserves at year-end 2016. Our Uinta Basin operations can be divided into two areas: the Greater Monument Butte Unit (GMBU) waterflood and an area to the north and adjacent to the GMBU that we refer to as the Central Basin. We have taken considerable steps to reduce our operating expenses in the GMBU. Although we are not actively drilling development wells today, we continue to inject water into the GMBU to advance the waterflood development. In the Central Basin, we continue to execute a horizontal drilling joint venture program to better understand our drilling and completion strategies and to improve the economics of plays in the Uteland Butte and

Wasatch formations. Our net production from the Uinta Basin during the fourth quarter of 2016 averaged approximately 15 MBOEPD (87% oil and 3% NGLs), a decrease of 17% as compared to the fourth quarter of 2015.

Williston Basin. We have approximately 82,000 net acres in the Williston Basin. This basin represents about 10% of our consolidated proved reserves at year-end 2016. Fourth quarter 2016 net production averaged approximately 16 MBOEPD (67% oil and 18% NGLs), a decrease of 16% compared to the fourth quarter of 2015.

China. Approximately 5 MMBbls, or 1%, of our proved reserves at year-end 2016 are located offshore China. Our Pearl development, located in the South China Sea, had average net production of 11 MBOPD in the fourth quarter 2016. No additional development drilling is currently planned at Pearl, and cash flow from China is funding a portion of our domestic drilling programs. In January 2017, we signed an agreement, subject to customary regulatory approval, to sell our non-operated interest in Bohai Bay for $39 million, subject to customary post-close adjustments, and expect the sale to close in mid-2017. Production from our interest in Bohai Bay was 578 MBbls for the year ended December 31, 2016. Our net proved reserves for our interest in the Bohai Bay field were 3,085 MBbls.

Acquisitions and Divestitures

During 2016, we acquired additional properties in the Anadarko Basin STACK play for an adjusted purchase price of $476 million, subject to customary post-close adjustments. Additionally, we divested substantially all of our oil and gas assets in the Maverick and Gulf Coast basins of Texas for approximately $380 million. We received total proceeds of approximately $405 million associated with the continuing sale of non-strategic assets, including our Texas assets. These sales were consistent with our strategy over the last six years to monetize non-strategic assets to improve our focus on domestic resource plays, reduce overall debt and enhance liquidity. Over this period, we received proceeds of approximately $3.0 billion for sales of non-strategic assets.

Reserves

Estimates of Proved Reserves

All reserve information in this report was based on estimates prepared by our petroleum engineering staff and is the responsibility of management. The preparation of our oil and gas reserves estimates was completed in accordance with our prescribed internal control procedures, which include verification of data input into our reserves forecasting and economics evaluation software, as well as multi-discipline management reviews, as described below. The technical employee responsible for overseeing the preparation of the reserves estimates has a Bachelor of Science in Petroleum Engineering, with more than 35 years of industry experience (including over 25 years of experience in reserve estimation).

Ryder Scott Company (Ryder Scott) and DeGolyer and MacNaughton (D&M) performed audits of the internally prepared reserve estimates on certain fields aggregating to 93% of 2016 year-end reported proved reserve quantities on a barrel of oil equivalent basis. The purpose of these audits was to provide additional assurance on the reasonableness of internally prepared reserve estimates. Newfield's proved reserves are, in the aggregate, reasonable and within the established audit tolerance guidelines of 10 percent, as set forth in the auditing standards published by the Society of Petroleum Engineers. The reports of Ryder Scott dated January 18, 2017 and D&M dated January 24, 2017 contain further discussion of the reserve estimates and their audit procedures, as well as the qualifications of the technical person primarily responsible for overseeing such estimates. Both reports are attached as exhibits to this annual report and incorporated herein by reference. See Exhibits 99.1 and 99.2.

Our reserves estimates use available geological and reservoir data as well as production performance data. Our petroleum engineering staff review estimates annually with management and revise the estimates, either upward or downward, as warranted by available data. The data reviewed includes, among other things, seismic data, well logs, production tests, reservoir pressures and individual well and field performance data. The data incorporated into our interpretations includes structure and isopach maps, individual well and field performance and other engineering and geological work products such as material balance calculations and reservoir simulation to arrive at conclusions about individual well and field projections. Additionally, offset performance data, operating expenses, marketing agreements, capital costs and product prices factor into estimating quantities of reserves. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental regulations, as well as changes in the expected recovery rates associated with development drilling. Sustained decreases in prices, for example, may cause a reduction in some reserves due to reaching their economic limits sooner.

Actual quantities of reserves recovered will most likely vary from the estimates set forth below. Reserves and cash flow estimates rely on interpretations of data and require assumptions that may be inaccurate. For a discussion of these interpretations and assumptions, see "Actual quantities of oil, natural gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates" under Item 1A, "Risk Factors," of this report. See "Supplementary Financial Information — Supplementary Oil and Gas Disclosures" to our consolidated financial statements in Item 8 of this report for additional reserves disclosures.

The table below summarizes our estimates of proved reserves at December 31, 2016.

	Proved Reserves (MMBOE)	Percentage of Proved Reserves	
Domestic:			
Anadarko Basin	330	64	%
Arkoma Basin	59	12	%
Uinta Basin	68	13	%
Williston Basin	49	10	%
Other	2	—	%
Total domestic	508	99	%
International:			
China	5	1	%
Total	513	100	%

The following table shows a summary of our estimates of proved oil and gas reserves by country at December 31, 2016.

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
Proved Developed Reserves:				
Domestic	104	928	50	309
China	5	—	—	5
Total proved developed	109	928	50	314
Proved Undeveloped Reserves:				
Domestic	81	438	45	199
China	—	—	—	—
Total proved undeveloped	81	438	45	199
Total proved reserves	190	1,366	95	513

Total Proved Reserves

Our estimates of proved reserves and related standardized measure of future net cash flows and PV-10 as of December 31, 2016 are calculated based upon SEC pricing, which uses a twelve-month unweighted average first-day-of-the-month oil and natural gas benchmark prices, adjusted for marketing and other differentials. While SEC pricing for crude oil, domestic natural gas and NGLs has been volatile since December 2014, the current strip as of February 16, 2017 is above the current SEC pricing for oil and natural gas. Future changes in SEC pricing will impact future estimated proved reserve volumes.

Our year-end 2016 proved reserves of 513 MMBOE consisted of 304 MMBOE proved developed producing, 10 MMBOE proved developed non-producing and 199 MMBOE proved undeveloped reserves. Our proved liquids reserves at year-end 2016 were 285 MMBbls, compared to 291 MMBbls at year-end 2015, a decrease of 2%. During 2016, crude oil and condensate reserves decreased 17 MMBbls while NGL reserves increased 11 MMBbls. At year-end 2016, 67% of our proved liquids reserves were crude oil or condensate. At December 31, 2016, our proved natural gas reserves were 1,366 Bcf, a 5% increase compared to 2015.

At December 31, 2016, the SEC pricing for natural gas was $2.48 per MMBtu, a 4% decrease compared to the prior year end, and pricing for oil was $42.82 per barrel, a 15% decrease compared to the prior year end. As a result, we revised our total proved reserves downward by 22 MMBOE for pricing changes; however, with cost structure improvement we were able to recapture 7 MMBOE of reserves. During 2016, we had a positive 36 MMBOE performance revision, primarily associated with the Anadarko Basin, which resulted in a net upward revision of 21 MMBOE for the year.

During 2016, we added proved reserves of 77 MMBOE, which included 35 MMBOE of reserves purchased and 42 MMBOE added through extensions, discoveries and other additions. Additionally, we sold non-strategic assets of 35 MMBOE and produced 59 MMBOE. Consistent with our continued focus on domestic liquids, our 2016 additions through extensions, discoveries and other additions were entirely domestic and 64% liquids (19 MMBbls of oil and 8 MMBbls of NGLs).

Proved Undeveloped Reserves

Our estimates of proved undeveloped reserves at December 31, 2016 were 199 MMBOE compared to 180 MMBOE at December 31, 2015. Liquids comprised 63% of our total proved undeveloped reserves at December 31, 2016. SCOOP and STACK represented 27% and 61% of our year-end proved undeveloped reserves, respectively. During 2016, we invested approximately $200 million of drilling, completion and facilities-related capital to convert 25 MMBOE of our December 31, 2015 proved undeveloped reserves into proved developed reserves. In 2016, we had negative price revisions of 9 MMBOE, which were offset by lower service costs, improved well performance and infill drilling revisions of 23 MMBOE. During 2016, we added 19 MMBOE of new proved undeveloped reserves through extensions, discoveries and other additions. Sales and acquisitions in 2016 led to an 11 MMBOE net increase. We continually assess the economic viability of our proved undeveloped reserves and direct capital resources to develop the areas that will provide the highest rate of return.

Estimates of proved undeveloped reserve quantities are limited by development drilling activity we intend to undertake during the 2017 to 2021 five-year period. For additional information regarding the changes in our proved reserves, see our "Supplementary Financial Information — Supplementary Oil and Gas Disclosures" to our consolidated financial statements in Item 8 of this report.

During the years 2014, 2015 and 2016, we developed 22%, 20% and 14%, respectively, of our prior year-end proved undeveloped reserves. The Company annually reviews all proved undeveloped reserves to ensure an appropriate development plan exists. Changes in commodity pricing between the time of preparation of the reserve report and actual investment, investment alternatives that may have been added to our portfolio of assets, changes in the availability and costs of oilfield services, and other economic factors may lead to changes in our development plans. As a result, the future rate at which we develop our proved undeveloped reserves may vary from historical development rates. Declines in oil and natural gas prices in the future could also render some of our proved undeveloped reserves uneconomic at future SEC pricing or compel us to reevaluate our project commitments to certain development projects.

Reserves Concentration

The table below sets forth the concentration of our proved reserves attributable to our largest fields (those whose reserves are greater than 15% of our total proved reserves). Our two largest fields, SCOOP and STACK, accounted for approximately 64% of our total proved reserves at December 31, 2016.

	Percentage of Proved Reserves
Ten largest fields	99%
Two largest fields	64%

Largest Fields. The table below sets forth the annual production volumes, average realized prices and related production cost structure on a per unit-of-production basis for our two largest fields. For a discussion regarding our total domestic and international annual production volumes, average realized prices, related cost structure and information about our contractual obligations and delivery commitments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," which disclosure is incorporated herein by reference.

	Year Ended December 31,		
	2016	2015	2014
Production:			
Crude oil and condensate (MBbls)			
SCOOP	4,125	3,779	2,548
STACK	6,464	3,645	1,182
Natural gas (Bcf)			
SCOOP	47.9	43.2	34.5
STACK	25.7	11.0	3.6
NGLs (MBbls)			
SCOOP	5,356	4,871	4,762
STACK	3,175	1,396	458
Total production by field (MBOE)			
SCOOP	17,467	15,857	13,066
STACK	13,929	6,886	2,245
Average Realized Prices:(1)			
Crude oil and condensate (per Bbl)			
SCOOP	$39.27	$42.67	$85.66
STACK	41.59	42.99	84.13
Natural gas (per Mcf)			
SCOOP	$2.24	$2.38	$3.96
STACK	2.29	2.49	4.44
NGLs (per Bbl)			
SCOOP	$19.63	$18.97	$29.54
STACK	19.86	19.02	35.24
Average realized prices by field (per BOE)			
SCOOP	$21.45	$22.49	$37.94
STACK	28.14	30.61	58.65
Average Production Cost:(2)			
SCOOP			
Lease operating costs (per BOE)	$1.14	$1.33	$1.93
Transportation costs (per BOE)	4.19	4.15	2.65
STACK			
Lease operating costs (per BOE)	$2.54	$2.58	$5.42
Transportation costs (per BOE)	3.37	2.04	1.93

(1) Does not include impact of derivative gains or losses.

(2) Production costs include cost to operate and maintain our wells, related equipment and supporting facilities, including the cost of labor, well service and repair, gathering, processing, transportation, as well as production-related general and administrative costs. Production costs exclude severance taxes and property taxes.

Drilling Activity

The following table sets forth the number of oil and gas wells completed for each of the last three years.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Domestic:						
Productive	136	60	123	57	254	114
Nonproductive	—	—	1	1	—	—
China:						
Productive	—	—	—	—	—	—
Nonproductive	—	—	—	—	1	1
Exploratory well total	136	60	124	58	255	115
Development wells:						
Domestic:						
Productive	47	31	158	78	326	231
China:						
Productive	—	—	16	3	2	1
Development well total	47	31	174	81	328	232

We were in the process of drilling, completing or waiting on completing 30 gross (17 net) domestic wells at December 31, 2016.

Productive Wells

As of December 31, 2016, we had the following productive oil and gas wells.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
Domestic:						
Oil	2,779	2,059	980	204	3,759	2,263
Natural gas	874	649	948	117	1,822	766
China:						
Oil	6	3	63	8	69	11
Total:						
Oil	2,785	2,062	1,043	212	3,828	2,274
Natural gas	874	649	948	117	1,822	766
Total	3,659	2,711	1,991	329	5,650	3,040

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements or production sharing contracts. The operator supervises production, maintains production records, employs or contracts field personnel and performs other functions.

Acreage Data

The following tables list by geographic area interests we owned in developed and undeveloped oil and gas acreage at December 31, 2016, along with a summary by year of our undeveloped acreage scheduled to expire in the next five years. In most cases, the drilling of a commercial well or the filing and approval of a development plan or suspension of operations will hold the acreage beyond the expiration date. Domestic ownership interests are onshore and generally take the form of "working interests" in oil and gas leases that have varying terms. International ownership interests are offshore and arise from participation in production sharing contracts.

Total Acreage

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
	(In thousands)			
Domestic:				
Anadarko Basin	483	272	222	132
Arkoma Basin	311	145	9	2
Uinta Basin	147	111	177	106
Williston Basin	123	70	22	12
Other	445	157	385	208
Total domestic	1,509	755	815	460
China:	34	9	—	—
Total	1,543	764	815	460

At December 31, 2016, we owned mineral interests in 420,000 gross and 114,000 net acres. These interests do not expire.

Expiring Acreage

	Undeveloped Acres Expiring									
	2017		2018		2019		2020		2021	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(In thousands)									
Domestic:										
Anadarko Basin	81	53	50	26	51	33	1	—	—	—
Uinta Basin	43	26	12	6	24	17	8	3	12	7
Williston Basin	—	—	1	1	1	—	—	—	—	—
Other	81	62	127	62	28	12	18	11	12	9
Total	205	141	190	95	104	62	27	14	24	16

Title to Properties

We believe that we have satisfactory title to substantially all of our producing properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, joint development agreements, ordinary course liens incidental to operating agreements and for current taxes, development obligations under oil and gas leases or capital commitments under our production sharing contracts in China. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than the title investigation we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and 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 examinations with respect to substantially all of our active properties that we operate.

Marketing

Substantially all of our oil, natural gas and NGLs are sold at market-based prices to a variety of purchasers, primarily under short-term contracts (less than 12 months). We also have long-term contracts in the Uinta Basin at market-based prices, less a variable differential that becomes fixed below certain market price thresholds. For a list of purchasers of our production that accounted for 10% or more of our total revenues for the three preceding calendar years, see Note 1, "Organization and Summary of Significant Accounting Policies — Major Customers," to our consolidated financial statements in Item 8 of this report, which information is incorporated herein by reference. We believe that the loss of any of these purchasers would not have a material adverse effect on us because alternative purchasers are available.

Historically, our access to refining capacity outside of the Salt Lake City area has been restricted due to limited transportation and refining options because of the paraffin content of our Uinta Basin production. As such, we have two long-term agreements with two refineries in the Salt Lake City area that run through 2020 and 2025. See further discussion under "Contractual Obligations" in Item 7 of this report.

Competition

Competition in the oil and gas industry is intense, particularly with respect to the acquisition of properties and access to capital and credit markets. See the discussion under "Competition for, or the loss of, our senior management or experienced technical personnel may negatively impact our operations or financial results" and "Competition in the oil and gas industry is intense" in Item 1A of this report, which information is incorporated herein by reference.

Segment Information

For more information on our continuing operations by segment, see Note 18, "Segment Information," to our consolidated financial statements in Item 8 of this report.

Employees

As of February 16, 2017, we had 994 employees. All but 52 of our employees were located in the United States. None of our employees are covered by a collective bargaining agreement. We believe that relationships with our employees are satisfactory.

Regulation

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state, provincial, tribal, local, foreign and international regulations. An overview of these regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen resource or environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. See the discussion under the caption "We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business," in Item 1A of this report.

General Overview. Our oil and gas operations are subject to various federal, state, provincial, tribal, local, foreign and international laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- acquisition of seismic data;
- location of wells;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;

- drilling, casing and cementing of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production;
- spill prevention plans;
- protection of private and public surface and ground water supplies;
- emissions reporting, permitting or limitations;
- protection of endangered species and habitat;
- occupational safety and health;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- transportation of production; and
- export of natural gas.

Federal Regulation of Drilling and Production. Many of our domestic oil and gas leases are granted by the federal government and administered by the Bureau of Indian Affairs, the Office of Natural Resources Revenue or the Bureau of Land Management, or BLM, all federal agencies. BLM leases contain relatively standardized terms and require compliance with detailed regulations. Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the time during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban surface activity. Under certain circumstances, the BLM may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore in a number of states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, disclosure of hydraulic fracturing fluid composition, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Environmental Regulations. We are subject to various federal, state, provincial, tribal, local, foreign and international laws and regulations concerning occupational safety and health, oil and gas production, as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials (including hazardous wastes) and flowback or produced water;
- the emission of certain gases, including greenhouse gases, or other materials into the atmosphere;

- the construction and placement of wells;
- the investigation, monitoring, abandonment, reclamation and remediation of wells and other sites, including sites of former operations;
- various environmental reporting and permitting requirements;
- the development of emergency response and spill contingency plans;
- disclosure of chemicals used in hydraulic fracturing; and
- protection of private and public surface and ground water supplies.

We consider the costs of environmental regulatory compliance and occupational safety and health compliance necessary and manageable parts of our business. We have been able to plan for and comply with environmental regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increased stringency, our capital expenditures and operating expenses related to the protection of the environment and occupational safety and health compliance have increased over the years and will likely continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters, and the cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial, property and natural resource damage payment obligations, or the issuance of injunctive relief (including orders to limit or cease operations altogether).

Oil and gas activities have increasingly faced opposition from environmental organizations and, in certain areas, have been restricted or banned by governmental authorities in response to concerns regarding the prevention of pollution or the protection of the environment. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties at sites we currently own or where we have sent wastes for disposal. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of drilling, or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected. The following is a summary of some of the environmental laws to which our operations are subject.

Hazardous Wastes and Substances. The Resource Conservation and Recovery Act, or RCRA, generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy," the EPA and state agencies may regulate these wastes as solid wastes. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely access its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Removal of RCRA's exemption for exploration and production wastes has the potential to significantly increase our waste disposal costs, which in turn will result in increased operating costs and could adversely impact our results of operations. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste, if they have hazardous characteristics.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a "hazardous substance" into the environment. Such "responsible parties" may be subject to joint and several liability under the Superfund law for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease onshore properties that have been used for the exploration and production of oil and natural gas for a number of years. Many of these onshore properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been disposed or released on them may be subject to the Superfund law, RCRA and analogous state laws and common law obligations, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

The federal Clean Air Act, or CAA, and comparable state statutes regulate and limit the emission of air pollutants by the Company and affect our oil and gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed and continues to develop more stringent regulations governing emissions of air pollutants, and is considering the expanded regulation of existing air pollutants and additional air pollutants. For example, in October 2015 the EPA lowered the National Ambient Air Quality Standard, or NAAQS, for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the EPA promulgated regulations that are designed to reduce the emission of volatile organic chemicals, or VOCs, by requiring oil and gas companies to utilize "green completions" to capture VOCs and other air pollutants when natural gas wells are fracked. More recently, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. Such regulations may increase the costs of compliance for some facilities or the market price for oil and natural gas.

Hydraulic Fracturing. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on almost all of our U.S. onshore oil and natural gas properties. Hydraulic fracturing involves using water, sand or other proppant materials, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the BLM, and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. Certain municipalities have already banned hydraulic fracturing, and courts have upheld those moratoria in some instances. In the past several years, dozens of states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing.

At the federal level, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; finalized regulations in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants; and issued in May 2014 an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Also, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including, for example, notice to and pre-approval by BLM of the proposed hydraulic fracturing activities; development and pre-approval by BLM of a plan for managing and containing flowback fluids and produced water recovered during the hydraulic fracturing process; implementation of measures designed to protect usable water from hydraulic fracturing activities; and public disclosure of the chemicals used in the hydraulic fracturing fluid. The rule has been challenged in federal court and implementation has been stayed pending a final decision.

In addition, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. The adoption of new federal rules or regulations relating to hydraulic fracturing could lead to increased operating costs, delays and curtailment in the pursuit of exploration, development or production activities, which in turn could materially adversely affect our operations. Several governmental reviews are underway that focus on environmental aspects of hydraulic fracturing activities. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, we do not believe that this multi-year study report provides any basis for further regulation of hydraulic fracturing at the federal level.

Based on the foregoing, increased regulation and attention given to the hydraulic fracturing process from federal agencies, various states and local governments 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 and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any 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 and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Climate Change. In response to findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, pre-construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Furthermore, in June 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission, and storage activities. The rules include first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rules impose leak detection and repair requirements intended to address methane leaks known as "fugitive emissions" from equipment, such as valves, connectors, open-ended lines, pressure-relief devices, compressors, instruments and meters. The EPA has also announced that it intends to impose methane emission standards for existing sources as well; while the agency has issued information collection requests to operators, to date, it has not yet issued a proposal. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment, such as optical gas imaging instruments to detect leaks, and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require additional personnel time to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations. The BLM finalized similar regulations designed to reduce methane emissions for oil and gas activities on federal lands in November 2016 that seek to impose limits on venting and flaring and would require enhanced leak detection and repair programs. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations. At this time, we have not developed a plan to address the potential social, political, economic and physical impacts of climate change on our operations.

Clean Water Act. Discharges to waters of the U.S. are further regulated and limited under the federal Clean Water Act, or CWA, and analogous state and tribal laws. The CWA prohibits any discharge of pollutants into waters of the United States, including wetland areas, except in compliance with permits issued by federal and state governmental agencies. In September 2015, new U.S. Environmental Protection Agency, or the EPA, and U.S. Army Corps of Engineers, or the Corps, rules defining the scope of the EPA's and the Corps' jurisdiction became effective. To the extent the rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. The process for obtaining permits has the potential to delay the development of natural gas and oil projects. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure or "SPCC" plans.

Safe Drinking Water Act. In addition, while the federal Safe Drinking Water Act, or SDWA, generally excludes hydraulic fracturing from the definition of underground injection, it does not exclude hydraulic fracturing involving the use of diesel fuels. In 2014, the EPA issued draft permitting guidance governing hydraulic fracturing with diesel fuels. While we do not use diesel fuels in our hydraulic fracturing fluids, we may become subject to federal permitting under SDWA if our fracturing formula changes. In addition, the SDWA grants the EPA broad authority to take action to protect public health when an underground source of drinking water is threatened with pollution that presents an imminent and substantial endangerment to humans. The SDWA also regulates saltwater disposal wells under the Underground Injection Control Program. Recent concerns related to the operation of saltwater disposal wells and induced seismicity have led some states to impose limits on the total volume of produced water such wells can dispose of, order disposal wells to cease operations, or ban the construction of new wells. These seismic events have also resulted in environmental groups and local residents filing lawsuits against operators in areas where the events occur seeking damages and injunctions limiting or prohibiting saltwater disposal well construction activities and operations. A lack of saltwater disposal wells in the areas in which we operate could result in increased disposal costs for our operations if we are forced to transport produced water by truck, pipeline, or other method over long distances.

National Environmental Policy Act. The National Environmental Policy Act, or NEPA, requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. Compliance with this requirement may lead to additional costs and delays in permitting for operators as the BLM may need to prepare additional Environmental Assessments and more detailed Environmental Impact Statements, which would be available for public review and comment. Such reviews are often subject to legal challenges, which can result in additional operational delays. In addition, the White House Council on Environmental Quality recently issued final guidance requiring consideration of climate change impacts in NEPA reviews, which may result in requirements to deploy additional air pollution control measures. These additional requirements could increase our compliance costs and delay the completion of our exploration and development projects.

Endangered or Protected Species. The Endangered Species Act restricts activities that may affect federally-identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal or permanent ban on operations in affected areas. Similarly, the Migratory Bird Treaty Act, or MBTA, implements various treaties and conventions between the U.S. and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas.

Occupational Health and Safety. The Occupational Safety and Health Act, or OSHA, and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Federal Regulation of Sales and Transportation of Natural Gas. Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

Pursuant to authority delegated to it by the Energy Policy Act of 2005, or EPAct 2005, FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms which make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to use or employ any device, scheme, or artifice to defraud, to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity. Violation of these requirements, similar to violations of other NGA and FERC enforcement authorities, may be subject to investigation and penalties of up to $1 million per day per violation. FERC may also order disgorgement of profit and corrective action. We believe, however, that neither the EPAct 2005 nor the regulations promulgated by FERC as a result of the EPAct 2005 will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

The FERC has issued certain market transparency rules for the gas industry pursuant to its EPAct 2005 authority, which may affect some or all of our operations. The FERC issued a final rule in 2007, as amended by subsequent orders on rehearing (Order 704), which requires wholesale buyers and sellers of more than 2.2 million MMBtu of physical gas in the previous calendar year, including gas producers, gatherers, processors and marketers, to report, on May 1 of each year, beginning in 2009, aggregate volumes of gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices, as explained in Order 704. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704. The FERC issued a Notice of Inquiry in Docket No. RM13-1-000 seeking comments from the industry regarding whether it should require more detailed information from sellers of gas. In November 2015, the FERC issued an order determining that the Notice of Inquiry's proposed reporting requirement was not necessary, and Docket No. RM13-1-000 was terminated.
Our sales of oil and natural gas are also subject to anti-manipulation and anti-disruptive practices authority under the Commodity Exchange Act, or CEA, as amended by the Dodd-Frank Wall Street Reform Act and Consumer Reform Act (the Dodd-Frank Act), and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA, as amended by the Dodd-Frank Act, prohibits any person from using or employing any manipulative or deceptive device in connection with any swap, or a contract of sale of any commodity, or for future delivery on such commodity, in contravention of the CFTC’s rules and regulations. The CEA, as amended by the Dodd-Frank Act, also prohibits knowingly delivering or causing to be delivered false or misleading or inaccurate reports concerning market information or conditions that affect or tend to affect the price of any commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the EPA, the FERC, the CFTC and the courts. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. There is always some risk, however, that Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action the FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by the FERC and Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other crude oil and condensate producers. In addition, certain emergency orders issued in 2014 by the U.S. Department of Transportation imposed additional restrictions on the shipment of crude oil by rail from the Bakken Shale. The Pipeline and Hazardous Materials Safety Administration (the "PHMSA") and the Federal Railroad Administration (the "FRA") also adopted final rules in 2015 supplementing the emergency orders that enhance existing tank car safety requirements and add sampling and testing requirements for product transported by rail. More recently, in January 2017 PHMSA published an advanced notice of proposed rulemaking stating that the agency is considering establishing vapor pressure limits for the transportation of crude oil and potentially all Class 3 flammable liquid hazardous materials, regardless of the method of transportation. These developments could increase the costs associated with moving our products.

International Regulations. Our exploration and production operations in China are subject to various types of regulations similar to those described above. These regulations are imposed by various agencies under the People's Republic of China (PRC). For example, laws under the Provisional Regulations on Administration and Management of the Abandonment of Offshore Oil and Gas Producing Facilities enacted in 2010, regulate our development and production activities offshore China. There are several departments in charge of aspects of energy industry regulation in China, including, the Bureau of Energy, the Ministry of Land and Resources, the Ministry of Housing and Urban-Rural Development, the State Administration of Work

Safety, the Ministry of Environmental Protection, and the State Bureau of Tax. The PRC continues to develop environmental laws, regulations and controls surrounding offshore developments. In many cases, the legal requirements may be similar in form to the U.S. regulations; however, they impose additional or more stringent conditions or controls that can significantly alter or delay the development of a project or substantially increase the cost of doing business in China.

Financial Information

Financial information regarding the geographic areas in which we operate is incorporated herein by reference to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8, "Financial Statements and Supplementary Data." Risks associated with our international operations are discussed under Item 1A, "Risk Factors," which information is incorporated herein by reference.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business and in this report.

Barrel or Bbl. One stock tank barrel or 42 U.S. gallons of liquid volume.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular derivative transaction.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent.

BLM. The Bureau of Land Management of the United States Department of the Interior.

BOE. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate, or 42 U.S. gallons for NGLs.

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

Btu. 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.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Developed acres. The number of acres that are allocated or assignable to producing wells or wells capable of production.

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.

Exploration well. A well drilled to find a new field or new 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.

FERC. The Federal Energy Regulatory Commission.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. Used synonymously with the term "Resource play."

FPSO. A floating production, storage and off-loading vessel commonly used overseas to produce oil from locations where pipeline infrastructure is not available.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

Infill drilling or infill well.   A well drilled between known producing wells to improve oil and gas reserve recovery.

Liquids.   Crude oil and NGLs.

Liquids-rich.   Formations that contain crude oil or NGLs instead of, or as well as, natural gas.

MBbls.   One thousand barrels of crude oil or other liquid hydrocarbons.

MBOE.   One thousand barrels of oil equivalent.

MBOEPD.   One thousand barrels of oil equivalent per day.

MBOPD.   One thousand barrels of oil per day.

Mcf.   One thousand cubic feet of natural gas.

Mcfe.   One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

MMBbls.   One million barrels of crude oil or other liquid hydrocarbons.

MMBOE.   One million barrels of oil equivalent.

MMBtu.   One million British thermal units.

MMcf.   One million cubic feet of natural gas.

MMcf/d.   One million cubic feet of natural gas produced per day.

MMcfe.   One million cubic feet equivalent.

MMMBtu.   One billion British thermal units.

Net acres or net wells.   The sum of the fractional working interests we own in gross acres or gross wells.

NGL.   Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasolines.

NYMEX.   The New York Mercantile Exchange.

NYMEX Henry Hub.   The major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

Play.   A group of fields or prospects in the same region that are controlled by the same set of geological circumstances. See also "Resource play."

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

Proved developed reserves. In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

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

Proved undeveloped reserves. In general, proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

PV-10. The pre-tax present value of estimated future gross revenues from the production of proved reserves, based on year-end SEC pricing, net of estimated future production, development and abandonment costs, based on year-end costs, discounted at an annual discount rate of 10%. After-tax PV-10 is referred to as the standardized measure.

Reserve life index. This index is calculated by dividing total proved reserves on an equivalent basis at year end by annual production to estimate the number of years of remaining production.

Resource play. A play targeting tight sand, coal bed or shale reservoirs. 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 horizontal drilling and stimulation treatments or other special recovery processes in order to be produced economically.

SCOOP. South-Central Oklahoma Oil Province. A resource play in the Anadarko Basin of Oklahoma.

SEC pricing. The unweighted average first-day-of-the-month commodity price for crude oil (WTI) or natural gas (NYMEX) for the prior 12 months. The SEC provides a complete definition of the pricing methodology in their guidance "Modernization of Oil and Gas Reporting."

STACK. Sooner Trend Anadarko Canadian Kingfisher. A resource play in the Anadarko Basin of Oklahoma.

Tcf. One trillion cubic feet of natural gas.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production and requires the owner to pay a share of the costs of drilling and production operations.

WTI. West Texas Intermediate, a grade of crude oil commonly used as a benchmark in oil pricing.

Additional Information

Through our website, www.newfield.com, Newfield provides access to electronic copies of our governance documents free of charge, including our Board of Directors’ Corporate Governance Guidelines and the charters of the committees of our Board of Directors. In addition, Newfield provides access to the documents we file with the U.S. Securities and Exchange Commission (SEC), including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, including all amendments thereto, as soon as reasonably practicable after we file or furnish them. The public also may request printed copies of our SEC filings or governance documents, free of charge, by writing to our corporate secretary at the address on the cover of this report. Additionally, the electronic copy of our most recent Corporate Responsibility report can be obtained through our website. Information contained on our website is not incorporated herein by reference and should not be considered part of this report.

In addition, 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, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Our corporate headquarters are located at 4 Waterway Square Place, Suite 100, The Woodlands, Texas 77380, and our telephone number is (281) 210-5100.

Item 1A. Risk Factors

There are many factors that may affect Newfield's business and results of operations. Described below are certain risks that we believe are particularly applicable to our business and the oil and gas industry in which we operate, which may adversely affect our business, financial condition, results of operations or cash flows. You should carefully consider, in addition to the other information contained in this report, the risks described below. We may experience additional risks and uncertainties not currently known to us or, as a result of development occurring in the future, conditions that we currently deem to be immaterial may also adversely affect our business, financial condition, results of operations or cash flows.

Oil, natural gas and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability, cash flows and future growth, as well as liquidity and ability to access additional sources of capital, depend substantially on prevailing prices for oil, natural gas and NGLs. Sustained lower prices will reduce the amount of oil, natural gas and NGLs that we can economically produce and may result in further impairments of our proved reserves or reduction of our proved undeveloped reserves. Oil, natural gas and NGL prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. See Items 1 and 2, "Business and Properties — 2017 Outlook," for additional information about the commodity price environment.

The market prices for oil, natural gas and NGLs depend on factors beyond our control. Some, but not all, of the factors that can cause fluctuations include:

- the domestic and foreign supply of, and demand for, oil, natural gas and NGLs;
- domestic and world-wide economic conditions;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- military, economic and political conditions in oil and gas producing regions;
- the actions taken by OPEC and other foreign oil and gas producing nations, including the ability of members of OPEC to agree to and maintain production controls;
- the impact of the U.S. dollar exchange rates on oil, natural gas and NGL prices;
- the price and availability of, and demand for, alternative fuels;
- weather conditions and climate change;
- world-wide conservation measures;
- technological advances affecting energy consumption and production;
- changes in the price of oilfield services and technologies;
- the price and level of foreign imports;
- expansion of U.S. exports of oil, natural gas and/or NGLs;
- the availability, proximity and capacity of transportation, processing, storage and refining facilities;
- the costs of exploring for, developing, producing, transporting and marketing oil, natural gas and NGLs; and
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental regulations.

While we cannot predict commodity prices, we have made adjustments in response to the current strong supply and relatively soft demand, such as adapting our 2017 capital investment plan to reflect anticipated commodity prices, historical drilling success, and markets for our products. These adjustments are likely to influence our profitability and could adversely affect our business, financial condition, results of operations and cash flows. In addition, our stock price in the market is influenced by fluctuations in oil, natural gas and NGL prices.

Sustained material declines in oil, natural gas or NGL prices may have the following effects on our business:

- limit our access to sources of capital, such as equity and long-term debt;
- cause us to delay or postpone capital projects;
- cause us to lose certain leases because we fail to develop the leases prior to expiration;
- reduce reserve estimates and the amount of products we can economically produce;
- downgrade or other negative rating action with respect to our credit rating;
- reduce revenues, income and cash flows available for capital expenditures, repayment of indebtedness and other corporate purposes; or
- reduce the carrying value of our assets in our balance sheet through ceiling test impairments.

We may be responsible for decommissioning liabilities for offshore interests we no longer own. Under state and federal law, oil and gas companies are obligated to plug and abandon (P&A) a well and restore the lease to pre-operating conditions after operations cease. U.S. state and federal regulations allow the government to call upon predecessors in interest of oil and gas leases to pay for P&A, restoration and decommissioning obligations if the current operator fails to fulfill those obligations. Moreover, offshore P&A liabilities can be very significant. As part of our strategic shift from offshore Gulf of Mexico operations to onshore U.S. operations, we divested our assets on the outer continental shelf (OCS) in the Gulf of Mexico (GoM). In connection with those divestitures, we entered into various arrangements with the purchasers whereby the purchasers assumed our P&A liabilities and other liabilities related to decommissioning such GoM assets. Since we began our strategic shift, several onshore and offshore E&P companies have sought bankruptcy protection. For example, in 2012 an offshore operator entered bankruptcy proceedings and sought to discharge its P&A liabilities in bankruptcy. The bankruptcy court allowed the discharge because the government identified a predecessor in interest of the lease to perform the P&A obligations. The predecessor in interest was forced to accept P&A liabilities estimated at over $100 million. If purchasers of our former GoM assets, or any successor owners of those assets, are unable to meet their P&A and other decommissioning obligations due to bankruptcy, dissolution or other related liquidity issues, we may be unable to rely on our arrangements with them to fulfill (or provide reimbursement for) those obligations. In those circumstances, the government may seek to impose the bankrupt entity's P&A obligations on us and any other predecessors in interest. Such payments could be significant and adversely affect our business, results of operations, financial condition and cash flows.

Moreover, recent changes to the Bureau of Ocean Energy Management's (BOEM) bonding requirements have the potential to adversely impact the financial condition of operators in the GoM and increase the number of operators seeking bankruptcy protection, given the current commodities market. In July 2016, BOEM issued a Notice to Lessees and Operators (NTL) that augments requirements for the posting of additional financial assurance by offshore lessees, among others, to assure that sufficient funds are available to perform decommissioning obligations with respect to offshore wells, platforms, pipelines and other facilities. The NTL, which became effective in September 2016, eliminates the agency's past practice of waiving supplemental bonding obligations where a company could demonstrate a certain level of financial strength. Instead, BOEM will allow companies to "self-insure," but only up to 10% of a company's "tangible net worth," which is defined as the difference between a company's total assets and the value of all liabilities and intangible assets. The NTL provides new procedures for how BOEM determines a lessee's decommissioning obligations, and the agency continues to negotiate with offshore operators to post additional financial assurance and develop tailored plans to meet BOEM's revised estimates for offshore decommissioning obligations. Projected decommissioning costs of operations in the GoM continue to increase, and the volatile price of oil and gas has adversely affected the net worth of many operators. BOEM's revisions to its supplemental bonding process could result in demands for the posting of increased financial assurance by the entities to whom we divested our GoM assets as well as other operators in the GoM. This will force operators to obtain surety bonds or other forms of financial assurance, the costs of which could be significant. Moreover, BOEM's NTL is likely to result in the loss of supplemental bonding waivers for a large number of operators on the OCS, which will in turn force these operators to seek additional surety bonds and could, consequently, exceed the surety bond market's ability to provide such additional financial assurance. Operators who have already leveraged their assets as a result of the volatile oil market could face difficulty obtaining surety bonds because of concerns the surety may have about the priority of their lien on the operators' collateral. Consequently, BOEM's changes could result in additional operators in the GoM initiating bankruptcy proceedings, which in turn could result in the government seeking to impose P&A costs on predecessors in interest in the event that the current operator cannot meet its P&A obligations. As a result, we could find ourselves liable to pay for the P&A costs of any entity we divested our GoM assets to, which payments could be significant and adversely affect our business, results of operations, financial condition and cash flows.

Legislation or regulatory initiatives intended to address seismic activity in Oklahoma and elsewhere could increase our costs of compliance or lead to operational delays, which could have a material adverse effect on our business, results of operations, cash flows or financial condition. Water sourcing, use and disposal are common practices in oil and gas operations. We dispose of large volumes of water produced alongside oil and natural gas “produced water” or "saltwater" in connection with our drilling and production operations, pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued under existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.
There exists a growing concern that the injection of produced water into belowground disposal wells triggers seismic events in certain areas, including Oklahoma, where we operate. In response to recent seismic events near underground water disposal wells, federal and some state agencies are investigating whether certain high volume disposal wells have caused or contributed to increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells that are located in close proximity to areas of increased seismic activity.
The Oklahoma Corporation Commission (OCC) evaluates existing disposal wells to assess their continued operation, or operation with restrictions, based on location relative to faults, seismicity and other factors, with well operators in certain geographic locations required to make frequent, or even daily, volume and pressure reports. In addition, the OCC has adopted rules requiring operators of certain saltwater disposal wells in the state to, among other things, conduct additional mechanical integrity testing or make certain demonstrations of such wells’ depth that, depending on the depth, could require the plugging back of such wells to shallower depths and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for wells within Areas of Interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. For example, OCC has established a 15 thousand square mile Area of Interest in the Arbuckle formation located primarily north and east of the Anadarko Basin in the Mississippi Lime play. Since 2013, OCC has prohibited disposal into the basement rock and ordered reduction of disposal volumes into the overlying Arbuckle formation and directed the shut-in of a number of Arbuckle disposal wells in response to seismic activity. In addition, in January 2016, the Governor of Oklahoma announced a grant of $1.4 million in emergency funds to support earthquake research to be directed by the OCC and the Oklahoma Geological Survey (OGS). During September and November 2016, in response to the occurrence of earthquakes in Cushing and Pawnee, Oklahoma, located in the northeast area of the Anadarko Basin, the OCC developed action plans in conjunction with the OGS and the EPA. The plans require reductions in disposal volumes in three concentric zones from the center of the earthquake activity in both Cushing and Pawnee, Oklahoma, with the greatest reductions in the zone located closest to the center of the largest quakes. These actions are in addition to any previous orders to shut in wells or reduce disposal volumes. Prior measures had already reduced disposal volumes in the areas of concern by up to 50 percent for some disposal wells. In the Pawnee area, the action plan covers a total of 38 Arbuckle disposal wells under OCC jurisdiction and 26 Arbuckle disposal wells under EPA jurisdiction and in the Cushing area the plan covers a total of 58 Arbuckle disposal wells. Local residents have also recently filed lawsuits against saltwater disposal well operators in these areas for damages resulting from the increased seismic activity.
Additionally, in recent years there has been increased public concern regarding an alleged potential for hydraulic fracturing to induce seismic events. For example, in July 2016, the OCC announced an investigation of all oil and gas activity, not solely disposal wells, in the Blanchard, Oklahoma area and other areas, in response to recent seismic activity in those areas. More recently, in December 2016, the OCC announced the development of seismicity guidelines focused on operators in SCOOP and STACK to directly address concerns related to induced seismicity and hydraulic fracturing. The OCC has established three action levels to be followed if events are detected at a M2.5 or above and within 1.24 miles (2 km) of hydraulic fracturing activities.

Magnitude 2.5 — OCC contacts the operator, discusses mitigation plan, operations may continue

Magnitude 3.0 — required minimum six-hour pause, technical call with OCC regarding mitigations, operations continue with an approved and revised completion plan

Magnitude 3.5 — required operations suspension, technical meeting with OCC and decision made to resume or halt operations based on approved and revised completion plan

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Restrictions on disposal well volumes or a lack of sufficient disposal wells, the filing of lawsuits, or curtailment or restrictions on oil and gas activity generally in response to concerns related to induced seismicity, could cause us to delay, curb or discontinue our exploration and development plans. Increased costs associated with restrictions on hydraulic fracturing or the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal or hydraulic fracturing, such as mandated produced water recycling in some portion or all of our operations or prohibitions on performing hydraulic fracturing in certain areas, may reduce our profitability. These developments may result in additional levels of regulation, or increased complexity and costs with respect to existing regulations, that could lead to operational delays or increased operating and compliance costs, which could have a material adverse effect on our business, results of operations, cash flows or financial condition.
Our use of oil and natural gas price derivative contracts may limit future revenues and cash flows from price increases and involves the risk that our counterparties may be unable to satisfy their obligations to us. Any inability to maintain our current derivative positions in the future specifically could result in financial losses or could reduce our income and cash flows. As part of our risk management program, we generally use derivative contracts to protect a substantial, but varying, portion of our anticipated future oil and gas production for the next 24 to 36 months to reduce our exposure to fluctuations in oil and natural gas prices. As of December 31, 2016, we had no outstanding derivative contracts related to our NGL production or market differentials. A significant portion of our oil derivative contracts include sold puts. If market prices remain below our sold puts at contract settlement, we will receive the difference between our floors or swaps and the associated sold puts, limiting the downside protection of these contracts. In the case of acquisitions, we may use derivative contracts to protect acquired production from commodity price volatility for a longer period. While the use of derivative contracts may limit or reduce the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements and expose us to the risk of financial loss in certain circumstances. Those circumstances include instances where our production is less than the volume subject to derivative contracts, there is a widening of price basis differentials between delivery points for our production and the delivery points assumed in the derivative transactions or there are issues with regard to the legal enforceability of such instruments.
The use of derivative transactions also involves the risk that counterparties, which generally are financial institutions, will be unable to perform their financial and other obligations under such transactions. If any of our counterparties were to default on its obligations to us under the derivative contracts, enter receivership or seek bankruptcy or similar protection, that could result in an economic loss to us and could have a material adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future production being subject to commodity price changes. In addition, in poor economic environments and tight financial markets, the risk of a counterparty default is heightened, and it is possible that fewer counterparties will participate in future derivative transactions, which could result in greater concentration of our exposure to any one counterparty or a larger percentage of our future production being subject to commodity price changes.
Additionally, in the past we have concluded that utilizing derivative contracts to lock in historically low prices for oil and natural gas for some of our anticipated future production is not in the best interest of the Company, and we may come to that conclusion again in the future. As a result, a meaningful portion of our future oil production could remain unhedged and subject to fluctuating market prices. If we are ultimately unable to, or choose not to, hedge additional expected oil production volumes for future periods, we will be subject to further potential commodity price volatility, which may result in lower than expected cash flows, revenues and income.
Our limited ability to hedge our NGL production and commodity basis differentials could adversely impact our cash flows and revenue. A liquid, readily available and commercially viable market for hedging NGL and commodity basis differentials has not developed in the same way that exists for oil and natural gas priced at WTI and Henry Hub, respectively. The current direct NGL and commodity basis differential hedging market is constrained in terms of price, volume, duration and number of counterparties. This limits our ability to hedge our NGL production and price difference based on point of sale effectively or at all. As a result, currently, we directly hedge only our oil and natural gas production priced at WTI and Henry Hub, respectively. If the current price levels for NGL continue or decrease in the future or the commodity basis differentials versus WTI or Henry Hub negatively increase, such as is the case with respect to our wax crude oil production, our cash flows and results of operations would be affected.

We have substantial capital requirements to fund our business plans that could be greater than cash flows from operations. Limited liquidity would likely negatively impact our ability to execute our business plan. Although we have set our capital expenditures in 2017 to more closely align with our projected cash flows, we anticipate that our 2017 capital investment levels may exceed our projected cash flows from operations in 2017. As a result, we may use available cash or borrow funds under our credit facility, due in part to our decision to continue our drilling program in order to avoid future lease renewals to retain certain acreage. If necessary, we may continue to use cash on hand, sell non-strategic assets or potentially access public debt and/or equity markets to fund any shortfall. Our ability to generate operating cash flows is subject to many risks and variables, such as the level of production from existing wells; prices of oil, natural gas and NGLs; production costs; availability of economical gathering, processing, storage and transportation in our operating areas; our success in developing and producing new reserves and the other risk factors discussed in this Annual Report.

Actual levels of capital expenditures may vary significantly due to many factors, including drilling results, commodity prices, industry conditions, the prices and availability of goods and services, unbudgeted acquisitions and the promulgation of new regulatory requirements. In addition, in the past, we often have increased our capital budget during the year as a result of acquisitions or changes in drilling plans. Alternatively, we may have to reduce capital expenditures, and our ability to execute our business plans could be adversely affected, if:

- we generate less operational cash flow than we anticipate;
- we are unable to sell non-strategic assets at acceptable prices due to low commodity prices;
- our customers or working interest owners default on their obligations to us;
- one or more of the lenders under our existing credit arrangements fails to honor its contractual obligation to lend to us;
- investors limit funding or refrain from funding oil and gas companies; or
- we are unable to access the capital markets at a time when we would like, or need, to raise capital.

Our level of indebtedness and the restrictive covenants in the agreements governing our indebtedness and other financial obligations may reduce our operating flexibility. As of December 31, 2016, we had total indebtedness of $2.4 billion. The indenture governing our outstanding notes and the agreements governing our other indebtedness and financial obligations contain, and any indenture that will govern other debt securities issued by us and any future agreements governing our other indebtedness and financial obligations may contain, various covenants that limit our ability and the ability of specified subsidiaries of ours to, among other things:

- incur additional indebtedness;
- purchase or redeem our outstanding equity interests or subordinated debt;
- make specified investments;
- create liens;
- sell assets;
- engage in specified transactions with affiliates;
- engage in sale-leaseback transactions; and
- effect a merger or consolidation with or into other companies or a sale of all or substantially all of our properties or assets.

These restrictions and our level of indebtedness could limit our ability to:

- obtain future financing;
- make needed capital expenditures;
- plan for, or react to, changes in our business and the industry in which we operate;
- compete with similar companies that have less debt;
- withstand a future downturn in our business or the economy in general; or
- conduct operations or otherwise take advantage of business opportunities that may arise.

Some of the agreements governing our indebtedness and other financial obligations also require the maintenance of specified financial ratios and the satisfaction of other financial conditions. Our ability to meet those financial ratios and conditions, and to comply with other covenants and restrictions in our financing agreements, can be affected by unexpected downturns in business operations beyond our control, such as a volatile commodity cost environment or an economic downturn. Accordingly, we may be unable to meet these obligations. This failure could impair our results of operations and cash flows and could restrict our ability to incur debt.

Our breach of any of these covenants could result in a default under the terms of the relevant indebtedness, which could cause such indebtedness or other financial obligations to become immediately due and payable. If the lenders accelerate the repayment of borrowings or other amounts owed, we may not have sufficient assets to repay our indebtedness or other financial obligations, including our outstanding notes and any future debt securities. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds from a sale of assets or a public offering of securities. Factors that will affect our ability to successfully complete a public offering, refinance our debt or conduct an asset sale include financial market conditions and our market value, asset valuations and operating performance at the time of such offering or other financing.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital. We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales, and near-term and long-term production growth opportunities. Liquidity, asset quality, cost structure, product mix, and commodity pricing levels are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt, and potentially require us to post letters of credit or other forms of collateral for certain obligations. A downgrade in our credit rating could negatively impact our cost of capital or our ability to effectively execute aspects of our strategy. If we were downgraded, it could be difficult for us to raise debt in the public debt markets and the cost of any new debt could be much higher than our outstanding debt. See Note 11, "Debt," to our consolidated financial statements in Item 8 of this report for additional information.

Actual quantities of oil, natural gas and NGL reserves and future cash flows from those reserves will most likely vary from our estimates. Estimating quantities of oil, natural gas and NGL reserves is complex and inexact. The process relies on interpretations of geologic, geophysical, engineering and production data. The extent, quality and reliability of these data can vary. The process also requires a number of economic assumptions, such as oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, the effect of government regulation, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions and our expected development plan; and
- the judgment of the persons preparing the estimate.

Actual quantities of oil, natural gas and NGL reserves, future production, oil, natural gas and NGL prices, revenues, taxes, capital expenditures, effects of regulations, funding availability and drilling and operating expenses will most likely vary from our estimates. In addition, the methodologies and evaluation techniques that we use, which include the use of multiple technologies, data sources and interpretation methods, may be different than those used by our competitors. Further, reserve estimates are subject to the evaluator’s criteria and judgment and show important variability, particularly in the early stages of development. Any significant variance could be systematic and undetected for an extended period of time, which would materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of reserves to reflect production history, results of exploration and development activities, prevailing oil, natural gas and NGL prices and other factors, many of which are beyond our control. Our reserves also may be susceptible to drainage by operators on adjacent properties.

In accordance with SEC requirements, we calculate the estimated discounted future net cash flows from proved reserves using the SEC’s pricing methodology for calculating proved reserves, adjusted for market differentials and costs in effect at year end discounted at 10%. Actual future prices and costs may be materially higher or lower than the prices and costs we used as of the date of an estimate. In addition, actual production rates for future periods may vary significantly from the rates assumed in the calculation. You should not assume that the present value of future net cash flows is the current market value of our proved reserves.

To maintain and grow our production and cash flows, we must continue to develop existing reserves and locate or acquire new reserves. Through our drilling programs and the acquisition of properties, we strive to maintain and grow our production and cash flows. However, as we produce from our properties, our reserves decline. Unless we successfully replace the reserves that we produce, the decline in our reserves will eventually result in a decrease in oil, natural gas and NGL production and lower revenue, income and cash flows from operations. Future oil, natural gas and NGL production is, therefore, highly dependent on our success in efficiently finding, developing or acquiring additional reserves that are

economically recoverable. We may be unable to find, develop or acquire additional reserves or production at an acceptable cost, if at all. In addition, these activities require substantial capital expenditures.

Lower oil and gas prices and other factors have resulted in ceiling test impairments in the past and may result in future ceiling test or other impairments. We use the full cost method of accounting for our oil and gas producing activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into cost centers that are established on a country-by-country basis. The net capitalized costs of our oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties. If net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test impairment to the extent of such excess. If required, a ceiling test impairment reduces income and stockholders' equity in the period of occurrence.

The risk that we will be required to further impair the carrying value of our oil and gas properties increases when oil, natural gas or NGL prices are low or volatile for a prolonged period of time. In addition, impairments may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase.

Drilling is a costly and high-risk activity. In addition to the numerous operating risks described in more detail below, the drilling of wells involves the risk that no commercially productive oil or gas reservoirs will be encountered. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil, natural gas or NGLs are present or may be produced economically. In addition, we are often uncertain of the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- increases in the costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- decreases in oil, natural gas and NGLs prices;
- limited availability to us of financing on acceptable terms;
- adverse weather conditions and changes in weather patterns;
- unexpected operational events and drilling conditions;
- abnormal pressure or irregularities in geologic formations;
- surface access restrictions;
- access to, and costs for, water needed in our waterflood project in the Greater Monument Butte Unit (GMBU);
- the presence of underground sources of drinking water, previously unknown water or other extraction wells or endangered or threatened species;
- embedded oilfield drilling and service tools;
- equipment failures or accidents;
- lack of necessary services or qualified personnel;
- availability and timely issuance of required governmental permits and licenses;
- loss of title and other title-related issues;
- availability, costs and terms of contractual arrangements, such as leases, pipelines and related facilities to gather, process and compress, transport and market oil, natural gas and NGLs; and
- compliance with, or changes in, environmental, tax and other laws and regulations.

Future drilling activities may not be successful, and if unsuccessful, this could have an adverse effect on our future results of operations, cash flows and financial condition.

The oil and gas business involves many operating risks that can cause substantial losses. Our oil and gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the risk of:

- fires and explosions;
- blow-outs and cratering;
- uncontrollable or unknown flows of oil, gas or well fluids;
- pipe or cement failures and casing collapses;
- pipeline or other facility ruptures and spills;
- equipment malfunctions or operator error;
- discharges of toxic gases;
- induced seismic events;
- environmental costs and liabilities due to our use, generation, handling and disposal of materials, including wastes, hydrocarbons and other chemicals; and
- environmental damages caused by previous owners of property we purchase and lease.

Some of these risks or hazards could materially and adversely affect our results of operations and cash flows 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 occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties or lawsuits;
- limitation on or suspension of our operations; and
- repairs and remediation costs to resume operations.

Further, offshore operations are subject to a variety of additional operating risks, such as capsizing, collisions and damage or loss from typhoons or other adverse weather conditions. These conditions could cause substantial damage to facilities and interrupt production. Our China operations are dependent upon the availability, proximity and capacity of gathering systems and processing facilities that we do not own. Necessary infrastructures have been in the past, and may be in the future, temporarily unavailable due to adverse weather conditions or other reasons, or they may not be available to us in the future on acceptable terms or at all.

In addition, our hydraulic fracturing operations require significant quantities of water. Regions in which we operate have recently experienced drought conditions. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs related to finding alternative water sources.

Failure or loss of equipment, as the result of equipment malfunctions, cyber-attacks or natural disasters, could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Catastrophic occurrences giving rise to litigation, such as a well blowout, explosion or fire at a location where our equipment and services are used, may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture could result in extensive environmental pollution and substantial remediation expenses, as well as governmental fines and penalties. If our production is interrupted significantly, our efforts at containment are ineffective or litigation arises as the result of a catastrophic occurrence, our cash flows, and in turn, our results of operations, could be materially and adversely affected.

In connection with our operations, we generally require our contractors, which include the contractor, its parent, subsidiaries and affiliate companies, its subcontractors, their agents, employees, directors and officers, to agree to indemnify us for injuries and deaths of their employees, contractors, subcontractors, agents and directors, and any property damage suffered by the contractors. There may be times, however, that we are required to indemnify our contractors for injuries and other losses resulting from the events described above, which indemnification claims could result in substantial losses to us. Contractor or customer contracts may also contain inadequate indemnity clauses, exposing us to unexpected losses or an unfavorable litigation position, and could, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flows.

While we maintain insurance against some potential losses or liabilities arising from our operations, our insurance does not protect us against all operational risks. The occurrence of any of the foregoing events and any costs or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage or not indemnified, could reduce revenue, income and cash flows and the funds available to us for our exploration, development and production activities and could, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flows. See also "— We may not be insured against all of the operating risks to which our business is exposed."

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including oil, natural gas and NGL prices, the availability of capital, costs, drilling results, regulatory approvals, available transportation capacity, and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified. Currently low oil prices, reduced capital spending and numerous other factors, many of which are beyond our control, could result in our failure to establish production on undeveloped acreage, and, if we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 65% of our total net undeveloped acreage at December 31, 2016. At that date, we had leases representing approximately 141,000 net undeveloped acres expiring in 2017, approximately 95,000 net undeveloped acres expiring in 2018, and approximately 62,000 net undeveloped acres expiring in 2019. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, results of operations, financial condition and cash flows.

Our proved undeveloped reserves may not be ultimately developed or produced. The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. At December 31, 2016, approximately 39% of our total estimated proved reserves (by volume) were undeveloped and may not be ultimately developed or produced. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Our reserve estimates assume we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove to be accurate. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled, or that the results of such development will be as estimated. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC’s reserve rules, because proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any proved undeveloped reserves that are not developed within this five-year time frame. A removal of such reserves could adversely affect our business and financial condition.

The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques on almost all of our U.S. onshore oil and natural gas properties. Hydraulic fracturing involves using water, sand or other proppant materials, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the BLM and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. Certain municipalities have already banned hydraulic fracturing, and courts have upheld those moratoria in some instances. In the past several years, dozens of states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing. See the risk factor "Legislation or regulatory initiatives intended to address seismic activity in Oklahoma and elsewhere could increase our costs of compliance or lead to operational delays, which could have a material adverse effect on our business, results of operations, cash flows or financial condition" for more information on action taken by certain states to regulate hydraulic fracturing activity.

At the federal level, the EPA has taken numerous actions, including the following: final federal Clean Air Act regulations in 2012 and, more recently, in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting; published in June 2016 an effluent limitation final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in May 2014 an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Also, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including, for example, notice to and pre approval by BLM of the proposed hydraulic fracturing activities; development and pre approval by BLM of a plan for managing and containing flowback fluids and produced water recovered during the hydraulic fracturing process; implementation of measures designed to protect usable water from hydraulic fracturing activities; and public disclosure of the chemicals used in the hydraulic fracturing fluid. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision is pending, however. In addition, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. The adoption of new federal rules or regulations relating to hydraulic fracturing could require us to obtain additional permits or approvals or to install expensive pollution control equipment for our operations, which in turn could lead to increased operating costs, delays and curtailment in the pursuit of exploration, development or production activities, which in turn could materially adversely affect our operations.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, we do not believe that this multi-year study report provides any basis for further regulation of hydraulic fracturing at the federal level.

Based on the foregoing, increased regulation and attention given to the hydraulic fracturing process from federal agencies, various states and local governments 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 NGLs, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any 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 and increased compliance costs and time, which could adversely affect our business, financial position, results of operations and cash flows.

Our ability to produce oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner. Development activities require the use of water. For example, the hydraulic fracturing process that we employ to produce commercial quantities of NGLs, natural gas and oil from many reservoirs requires the use and disposal of significant quantities of water in addition to the water we use to develop our waterflood in the GMBU. In certain regions, there may be insufficient local capacity to provide a source of water for drilling activities. In these cases, water must be obtained from other sources and transported to the drilling site, adding to the operating cost. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations, such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of NGLs, natural gas and oil. In recent history, public concern surrounding increased seismicity has heightened focus on our industry’s use of water in operations, which may cause increased costs, regulations or environmental initiatives impacting our use or disposal of water. See the risk factor "Legislation or regulatory initiatives intended to address seismic activity in Oklahoma and elsewhere could increase our costs of compliance or lead to operational delays, which could have a material adverse effect on our business, results of operations, cash flows or financial condition" for more information on action taken by certain states to regulate hydraulic fracturing activity with respect to induced seismicity. Furthermore, future environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could cause delays, interruptions or termination of operations, which may result in increased operating costs and have an effect on our business, results of operations, cash flows or financial condition.

The marketability of our production is dependent upon transportation and processing facilities over which we may have no control. The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. We deliver oil, natural gas and NGLs through gathering systems and pipelines that we do not own. The lack of available capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through some firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical or other reasons, or may not be available to us in the future at a price that is acceptable to us. New regulations on the transportation of oil by rail, like those finalized by the U.S. Department of Transportation (DOT) in 2015, may increase our transportation costs. In addition, federal and state regulation of natural gas and oil production, processing and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints and general economic conditions could adversely affect our ability to produce, gather and transport natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business. Existing and potential regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development and the production and sale of oil, natural gas and NGLs are subject to extensive federal, state, provincial, tribal, local and international regulation. We may be required to make large expenditures to comply with environmental, natural resource protection, and other governmental regulations. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (NAAQS) for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. More recently, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. Matters subject to regulation include the following, in addition to the other matters discussed under the caption "Regulation" in Items 1 and 2 of this report:

- restrictions for the protection of wildlife that regulate the time, place and manner in which we conduct operations;
- the amounts, types and manner of substances and materials that may be released into the environment;
- response to unexpected releases into the environment;
- reports and permits concerning exploration, drilling, production and other operations;
- the placement and spacing of wells;
- cement and casing strength;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials into the environment, remediation and clean-up costs, natural resource risk mitigation, damages and other environmental or habitat damages. We also could be required to install and operate expensive pollution controls, engage in environmental risk management, incur increased waste disposal costs, or limit or even cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. For example, in September 2015, a new joint EPA and U.S. Army Corps of Engineers rule under the federal Clean Water Act (CWA) defining the scope of the EPA's and the Corps' jurisdiction became effective. To the extent the rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. More recently, in December 2016, the EPA and environmental groups entered into a consent decree to address EPA's alleged failure to timely assess its Resource Conversation and Recovery Act (RCRA) Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. Removal of RCRA's exemption for exploration and production wastes has the potential to significantly increase our waste disposal costs, which in turn will result in increased operating costs and could adversely impact our results of operations.

In addition, failure to comply with applicable laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as the imposition of corrective action orders. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our business, financial condition, results of operations or cash flows.

The matters described above and other potential legislative proposals, along with any applicable legislation introduced and passed in Congress or new rules or regulations promulgated by state or the US federal government, could increase our costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, negatively impacting our financial condition, results of operations and cash flows. See also "— The potential adoption of federal, state, tribal and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells."

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our results of operations and cash flows, in addition to the demand for the oil, natural gas and NGLs that we produce.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects. In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration (PSD) pre-construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified 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 June 2016, the EPA published final rules establishing new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, as part of an overall effort to reduce methane emissions in the oil and natural gas source category by up to 45% from 2012 levels by the year 2025. The EPA's final rules include New Source Performance Standards (NSPS) to limit methane emissions from equipment and processes across the oil and natural gas source category. The rules also extend limitations on volatile organic compound (VOC) emissions to sources that were unregulated under the previous NSPS at Subpart OOOO. Affected methane and VOC sources include hydraulically fractured (or re-fractured) oil and natural gas well completions, fugitive emissions from well sites and compressors, and pneumatic pumps. The new methane and VOC standards require the implementation of the best system of emission reduction to achieve these emission reductions, mirroring the existing VOC standards under Subpart OOOO. These rules could require a number of modifications to our operations, including the installation of new equipment to control methane and VOC emissions from our operations as well as the hiring of additional personnel to perform equipment inspections. These requirements could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact or delay production activities, which could have a material adverse effect on our business. The BLM finalized similar regulations designed to reduce methane emissions for oil and gas activities on federal lands in November 2016 that seek to impose limits on venting and flaring and would require enhanced leak detection and repair programs. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations.

There has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional cap and trade programs have emerged, which typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce and lower the value of our reserves, which in turn could affect our profitability and stock price. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

We could be adversely affected by the credit risk of financial institutions. We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds and other institutions. In the event of default of a counterparty, we would be exposed to credit risks. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative contracts and insurance companies in the form of claims under our policies. In addition, if any lender under our credit facility or our money market lines of credit is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender’s commitment under our credit facility or our money market lines of credit.

We are exposed to counterparty credit risk as a result of our receivables. We are exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. We sell our oil, natural gas and NGLs to a variety of purchasers. Some of our purchasers and non-operating partners may experience credit downgrades or liquidity problems and may not be able to meet their financial obligations to us. Nonperformance by a trade creditor or non-operating partner could result in financial losses.

Federal legislation regarding swaps could adversely affect the costs of, or our ability to enter into, those transactions. Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which was passed by Congress and signed into law in July 2010, amends the Commodity Exchange Act (CEA) to establish a comprehensive new regulatory framework for over-the-counter derivatives, or swaps, and swaps market participants, such as Newfield. The Dodd-Frank Act requires certain swaps to be cleared through a derivatives clearing organization, unless an exception from mandatory clearing is available, and if the swap is subject to a clearing requirement, to be executed on a designated contract market or swap execution facility. To date, the CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet required the clearing of any other classes of swaps, including commodity swaps. Although we expect to qualify for the end-user exception from the clearing requirement for our swaps entered into to hedge our commercial risks, the application of the mandatory clearing requirements to other market participants, such as swap dealers, along with changes to the markets for swaps as a result of the trade execution requirement, may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap execution facility. In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce our liquidity and cash available for capital expenditures and could reduce our ability to manage commodity price volatility and the volatility in our revenues and cash flows. Therefore, we are unable to determine the future costs on our derivative activities at this time.

Higher costs associated with the Dodd-Frank Act can create disincentives for end-users like Newfield to hedge their commercial risks, including market price fluctuations associated with anticipated production of oil and gas. The Dodd-Frank Act and related rules and regulations promulgated by CFTC could potentially increase the cost of Newfield's risk management activities, which could adversely affect our available liquidity, materially alter the terms of our swap contracts, reduce the availability of swaps to hedge or mitigate risks we encounter, reduce our ability to monetize or restructure existing swap contracts, and increase our regulatory compliance costs related to our swap activities. In addition, if we reduce our use of swaps, our results of operations and cash flows may be adversely affected, including by becoming more volatile and less predictable, which also could adversely affect our ability to plan for and fund capital expenditures. It is also possible that the Dodd-Frank Act and related rules and regulations could affect prices for commodities that we purchase, use or sell, which, in turn, could adversely affect our liquidity, revenues, cash flows and financial condition.

In December 2013, the CFTC re-proposed rules to amend the CEA to establish position limits for certain commodity futures and options contracts, and physical commodity swaps that are economically equivalent to such contracts, including those derivative instruments that we use. If the CFTC position limit regulations are ultimately adopted substantially in the form proposed, they could result in additional compliance costs and alter our ability to effectively manage our commercial risks. Until the CFTC adopts final rules with respect to position limits and any exemptions for bona fide derivative transactions or off-setting positions from those limits, we will be unable to determine whether the CFTC's proposed rules could result in additional derivative costs or adversely affect our ability to effectively manage our commercial risks.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent Newfield transacts with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

A substantial majority of our producing properties are located in the SCOOP and STACK areas of Oklahoma, making us vulnerable to risks associated with operating in a single geographic area. A substantial majority of our producing properties are geographically concentrated in the SCOOP and STACK areas of Oklahoma. At December 31, 2016, 64% of our total estimated proved reserves were attributable to properties located in these areas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on the leases or units containing the leasehold acreage. For the year ended December 31, 2016, approximately 71% of our total net acreage was held by production. Leases on oil and gas properties normally have a term of three to five years and will expire unless, prior to expiration of the lease term, production in paying quantities is established. If the leases expire and we are unable to renew them, we will lose the right to develop the related properties. The risk of the foregoing increases in periods of sustained low commodity prices due to the corresponding impact on our drilling plans and the likely decrease in what is considered economic production under the leases. Our drilling plans for these areas are subject to change based upon various factors, including commodity prices, drilling results, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation. In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to:

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

Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations and cash flows.

We have risks associated with our China operations. Ownership of property interests and production operations in China are subject to the various risks inherent in international operations. These risks may include:

- currency restrictions, exchange rate fluctuations, or other activities that disrupt markets and restrict payments or the movement of funds;
- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, piracy, acts of terrorism, insurrection, civil unrest and other political risks or other changes in government;
- difficulties obtaining permits or governmental approvals as a foreign operator;
- taxation policies, including increases in taxes and governmental royalties, retroactive tax claims and investment restrictions;
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act and other anti-corruption compliance laws and issues;
- disruptions in international oil cargo shipping activities;
- physical, digital, internal and external security breaches;
- forced renegotiation of, unilateral changes to, or termination of contracts with, governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations in China;
- our limited ability to influence or control the operation or future development of non-operated properties;
- the operator's expertise or other labor problems;
- cultural differences;
- difficulties enforcing our rights against a governmental entity because of the doctrine of sovereign immunity and foreign sovereignty over our China operations; and
- other uncertainties arising out of foreign government sovereignty over our China operations.

Our China operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation, investment and transparency issues. In addition, if a dispute arises with respect to our China operations, we may be subject to the exclusive jurisdiction of non-U.S. courts or may not be successful in subjecting non-U.S. persons to the jurisdiction of the courts of the United States. Realization of any of the factors listed above could materially and adversely affect our financial position, results of operations or cash flows.

Competition for, or the loss of, our senior management or experienced technical personnel may negatively impact our operations or financial results. To a large extent, we depend on the services of our senior management and technical personnel and the loss of any key personnel could have a material adverse effect on our business, financial condition, results of operations and cash flows. Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain a seasoned management team and experienced explorationists, engineers, geologists and other professionals. In the past, competition for these professionals was strong, and in a continuing price recovery environment may become strong again, which could result in future retention and attraction issues.

Competition in the oil and gas industry is intense. We operate in a highly competitive environment for acquiring properties and marketing oil, natural gas and NGLs. Our competitors include multinational oil and gas companies, major oil and gas companies, independent oil and gas companies, individual producers, financial buyers as well as participants in other industries supplying energy and fuel to consumers. During these periods, there is often a shortage of drilling rigs and other oilfield services. Many of our competitors have greater and more diverse resources than we do. In addition, high commodity prices, asset valuations and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties. We compete for the personnel and equipment required to explore, develop and operate properties. Our competitors also may have established long-term strategic positions and relationships in areas in which we may seek new entry. As a consequence, our competitors may be able to address these competitive factors more effectively than we can. If we

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are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition, cash flows and results of operations may be adversely affected.

Shortages of oilfield equipment, services, supplies and qualified field personnel could adversely affect our financial condition, results of operations and cash flows. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for that equipment has increased along with the number of wells being drilled. The demand for qualified and experienced field personnel to drill wells and conduct field operations can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. These factors have caused significant increases in costs for equipment, services and personnel. Higher oil, natural gas, and NGL prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment, services and raw materials. Similarly, lower oil, natural gas and NGL prices generally result in a decline in service costs due to reduced demand for drilling and completion services.

Decreased levels of drilling activity in the oil and gas industry in recent periods have led to declining costs of some oilfield equipment, services and supplies. However, if the current oil and gas market changes, and commodity prices continue to recover, we may face shortages of field personnel, drilling rigs, or other equipment or supplies, which could delay or adversely affect our exploration and development operations and have a material adverse effect on our business, financial condition, results of operations or cash flows, or restrict operations.

We may not be insured against all of the operating risks to which our business is exposed. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, such as well blowouts, explosions, oil spills, releases of gas or well fluids, fires, pollution and adverse weather conditions, which could result in substantial losses to us. See also "— The oil and gas business involves many operating risks that can cause substantial losses." Exploration and production activities are also subject to risk from political developments such as terrorist acts, piracy, civil disturbances, war, expropriation or nationalization of assets, which can cause loss of or damage to our property. We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our insurance coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our onshore and offshore operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution and other environmental issues, with broader coverage for sudden and accidental occurrences. For example, we maintain operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operators extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims.

Further, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flows.

We may be subject to risks in connection with acquisitions and divestitures. As part of our business strategy, we have made and will likely continue to make acquisitions of oil and gas properties and to divest non-strategic assets. Suitable acquisition properties or suitable buyers of our non-strategic assets may not be available on terms and conditions we find acceptable or not at all.

Acquisitions pose substantial risks to our business, financial condition, cash flows and results of operations. These risks include that the acquired properties may not produce revenues, reserves, earnings or cash flows at anticipated levels. Also, the integration of properties we acquire could be difficult. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources. The successful acquisition of properties requires an assessment of several factors, including:

- recoverable reserves;
- exploration potential;
- future oil and natural gas prices and their relevant differentials;
- operating costs and production taxes; and
- potential environmental and other liabilities.

These assessments are complex and the accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

In addition, our divestitures may pose significant residual risks to the Company, such as divestitures where we retain certain liabilities or we have legal successor liability due to the bankruptcy or dissolution of the purchaser. See for example "— We may be responsible for decommissioning liabilities for offshore interests we no longer own." Generally, uneconomic or unsuccessful acquisitions and divestitures may divert management’s attention and financial resources away from our existing operations, which could have a material adverse effect on our financial condition, results of operations and cash flow.

We depend on computer and telecommunications systems, and failures in our systems or cyber security attacks could significantly disrupt our business operations. The oil and gas industry has become increasingly dependent upon digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Our business partners, including vendors, service providers, purchasers of our production and financial institutions, are also dependent on digital technology. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any cyber incidents or interruptions to our arrangements with third parties, to our computing and communications infrastructure or our information systems could lead to data corruption, communication interruption, unauthorized release, gathering, monitoring, misuse or destruction of proprietary or other information, or otherwise significantly disrupt our business operations. 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.

Hurricanes, typhoons, tornadoes, earthquakes and other natural disasters could have a material adverse effect on our business, financial condition, results of operations and cash flow. Hurricanes, typhoons, tornadoes, earthquakes and other natural disasters can potentially destroy thousands of business structures and homes and, if occurring in the Gulf Coast region of the United States, could disrupt the supply chain for oil and gas products. Disruptions in supply could have a material adverse effect on our business, financial condition, results of operations and cash flow. Damages and higher prices caused by hurricanes, typhoons, tornadoes, earthquakes and other natural disasters could also have an adverse effect on our business, financial condition, results of operations and cash flow due to the impact on the business, financial condition, results of operations and cash flow of our customers.

Our certificate of incorporation, bylaws, some of our arrangements with employees and Delaware law contain provisions that could discourage an acquisition or change of control of us. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to affect a change of control, to acquire us or to replace incumbent management, including, for example, limitations on stockholders’ ability to remove directors, call special meetings and to

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propose and nominate directors or otherwise propose actions for approval at stockholder meetings, as well as the ability of our board of directors to amend our certificate of incorporation and bylaws and to issue and set the terms of preferred stock without the approval of our stockholders. In addition, our change of control severance plan, change of control severance agreements with certain officers and our omnibus stock plans and deferred compensation plan contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of equity awards and acceleration of deferred compensation, upon a change of control. Section 203 of the Delaware General Corporation Law also imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions could discourage or prevent a change of control, even if it may be beneficial to our stockholders, or could reduce the price our stockholders receive in an acquisition of us.
Delays in obtaining licenses, permits, and other government authorizations required to conduct our operations could adversely affect our business. Our operations require licenses, permits, and in some cases renewals of licenses and permits from various governmental authorities. Our ability to obtain, sustain or renew such licenses and permits on acceptable terms is subject to changes in regulations and policies and to the discretion of the applicable government agencies, among other factors. Our inability to obtain, or our loss of or denial of extension, to any of these licenses or permits could hamper our ability to produce income, revenues or cash flows from our operations.

We may incur losses as a result of title defects in the properties in which we invest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the interest under the property.

As we continue to expand our operations in Oklahoma, North Dakota or Utah, we may operate within the boundaries of Native American reservations and become subject to certain tribal laws and regulations. An entirely separate and distinct set of laws and regulations applies to operators and other parties within the boundaries of Native American reservations in the United States. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and Bureau of Land Management (BLM), and the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, environmental standards, tribal employment contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and BLM. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members or use tribal owned service businesses and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are often subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

We therefore may become subject to various laws and regulations pertaining to Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas operations within Native American reservations. One or more of these Native American requirements, or delays in obtaining necessary approvals or permits necessary to operate on tribal lands pursuant to these regulations, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

We have been named as a defendant in a number of lawsuits and are involved in various other disputes, all arising in the ordinary course of our business, such as (a) claims from royalty owners for disputed royalty payments, (b) commercial disputes, (c) personal injury claims and (d) property damage claims. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

In August 2016, the North Dakota Department of Health (NDDH) announced its intent to resolve alleged systemic violations of the North Dakota air pollution control laws, N.D.C.C. ch. 23-25, N.D. Admin. Code art. 33-15, the North Dakota State Implementation Plan, and those provisions of the federal Clean Air Act and its body of implementing regulations for which the NDDH has been delegated authority by the U.S. Environmental Protection Agency (EPA), at the Company's facilities in North Dakota. The enforcement and settlement process results from EPA and North Dakota inspections of oil and gas facilities in North Dakota that revealed certain incidents of non-compliance at some facilities of the Company. Companies that voluntarily choose to enter into the Consent Decree do not admit any violations but choose to do so in order to avoid potentially harsher enforcement through subsequent inspections of operated facilities in North Dakota. The Company entered into a Consent Decree in February 2017 that includes a payment of civil penalties and compliance with the terms and conditions therein. The penalties to be paid are also subject to possible reductions for early compliance with certain conditions therein for at least two years. In addition to the stipulated penalty there will be additional conditions added to facility permits requiring the Company to review and analyze its facility designs, and implement inspection and maintenance programs, among other conditions contained therein. The Consent Decree is filed with the North Dakota District Court in Burleigh County and will be reduced to a court order subject to termination upon consent from the Department of Health that all terms of the Consent Decree have been completed to the Department’s satisfaction or after two years, or a company may petition the court for termination. We do not anticipate that these penalties will exceed $1 million.
In addition, from time to time we receive notices of violation from governmental and regulatory authorities in areas in which we operate related to alleged violations of environmental statutes or rules and regulations promulgated thereunder. We cannot predict with certainty whether these notices of violation will result in fines or penalties, or if such fines or penalties are imposed, that they would individually or in the aggregate exceed $100,000. If any federal government fines or penalties are in fact imposed that are greater than $100,000, then we will disclose such fact in our subsequent filings.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

The following table sets forth the names, ages (as of February 16, 2017) and positions held by our executive officers. Our executive officers serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
Lee K. Boothby	55	President, Chief Executive Officer and Chairman of the Board	17
Lawrence S. Massaro	53	Executive Vice President and Chief Financial Officer	6
Gary D. Packer	54	Executive Vice President and Chief Operating Officer	21
George T. Dunn	59	Senior Vice President — Development	24
John H. Jasek	47	Senior Vice President — Operations	17
Stephen C. Campbell	48	Vice President — Investor Relations	17
George W. Fairchild, Jr.	49	Chief Accounting Officer	5
Timothy D. Yang	44	General Counsel and Corporate Secretary	2
Matthew R. Vezza	43	Vice President — Assets	4

Lee K. Boothby was named Chairman of the Board of Directors in May 2010, Chief Executive Officer in May 2009 and President in February 2009. Prior to this, he was Senior Vice President — Acquisitions and Business Development. From 2002 to 2007, he was Vice President — Mid-Continent. From 1999 to 2001, Mr. Boothby was Vice President and Managing Director — Newfield Exploration Australia Ltd. and managed operations in the Timor Sea (divested in 2003) from Perth, Australia. Prior to joining Newfield in 1999, Mr. Boothby worked for Cockrell Oil Corporation, British Gas and Tenneco Oil Company. He serves as a board member for America’s Natural Gas Alliance and the American Exploration and Production Council. He is a member of the Louisiana State University Craft & Hawkins Department of Petroleum Engineering Advisory Committee, the Society of Petroleum Engineers, the Independent Petroleum Association of America and the Rice University Jones Graduate School of Business Council of Overseers. He holds a degree in Petroleum Engineering from Louisiana State University and a Master of Business Administration from Rice University.

Lawrence S. Massaro was promoted to Executive Vice President and Chief Financial Officer in November 2013. Mr. Massaro joined Newfield in March 2011 and served as Vice President — Corporate Development until November 2013. In this position, he led the Company's business development, strategic planning and product marketing efforts. Prior to joining Newfield, Mr. Massaro served as Managing Director at JP Morgan in its oil and gas investment banking group beginning in 2005 and was Vice President, Corporate Strategy and Business Development while at Amerada Hess Corporation from 1995 to 2005. He also held various senior petroleum engineering positions at both PG&E Resources from 1992 to 1994 and at British Petroleum from 1985 to 1991. Mr. Massaro holds a degree in Petroleum Engineering from Texas A&M University and a Master of Business Administration from Southern Methodist University.

Gary D. Packer was promoted to the position of Executive Vice President and Chief Operating Officer in May 2009. Prior thereto, he was promoted from Gulf of Mexico General Manager to Vice President — Rocky Mountains in November 2004. Mr. Packer joined the Company in 1995. Prior to joining Newfield, Mr. Packer worked for Amerada Hess Corporation in both the Rocky Mountains and Gulf of Mexico divisions. Prior to these roles, he worked for Tenneco Oil Company. In December 2014, Mr. Packer joined the board of directors of Bennu Oil & Gas, LLC, a private oil and gas company operating offshore in the Gulf of Mexico. He serves as a board member for the Independent Petroleum Association of America. He holds a degree in Petroleum and Natural Gas Engineering from Penn State University.

George T. Dunn was promoted to Senior Vice President — Development in September 2012, previously serving as Vice President — Mid-Continent beginning in October 2007. He managed our onshore Gulf Coast operations from 2001 to

October 2007, and was promoted from General Manager to Vice President in November 2004. Before managing our Gulf Coast operations, Mr. Dunn was the General Manager of our Western Gulf of Mexico division. Prior to joining Newfield in 1992, Mr. Dunn was employed by Meridian Oil Company and Tenneco Oil Company. He holds a degree in Petroleum Engineering from the Colorado School of Mines.

John H. Jasek was promoted to Senior Vice President — Operations in October of 2014, after serving as Vice President — Onshore Gulf Coast since February 2011. Prior to that, Mr. Jasek served as Vice President — Gulf of Mexico from December

2008 until February 2011 and as Vice President — Gulf Coast from October 2007 until December 2008. He previously managed our Gulf of Mexico operations from March 2005 until October 2007, and was promoted from General Manager to Vice President — Gulf of Mexico in November 2006. Prior to March 2005, he was a petroleum engineer in the Western Gulf of Mexico. Before joining Newfield, Mr. Jasek worked for Anadarko Petroleum Corporation and Amoco Production Company. He has a degree in Petroleum Engineering from Texas A&M University.

Stephen C. Campbell was promoted to Vice President — Investor Relations in December 2005, after serving as Newfield’s Manager — Investor Relations since 1999. Prior to joining Newfield, Mr. Campbell was the Investor Relations Manager at Anadarko Petroleum Corporation from 1993 to 1999 and the Assistant Vice President of Marketing & Communications at United Way, Texas Gulf Coast from 1990 to 1993. He is a member of the National Investor Relations Institute. He holds a Bachelor of Science degree in Journalism from Texas A&M University.

George W. Fairchild, Jr. was promoted to Chief Accounting Officer in November 2013. Mr. Fairchild joined Newfield in August of 2012 as Controller and has served as the Company’s Principal Accounting Officer since joining the Company. Prior to joining Newfield, Mr. Fairchild served as Controller for Sheridan Production Company LLC, a privately-held oil and gas company, beginning in 2009 and was Vice President and Controller of Davis Petroleum Corporation, also a privately-held oil and gas company, from 2006 to 2009. Prior thereto, Mr. Fairchild was with Burlington Resources Inc., a publicly-held oil and gas company, serving as Senior Manager — Accounting Policy & Research from 2001 to 2006 and Manager — Internal Audit from 2000 to 2001. Before joining Burlington Resources Inc., he was with PricewaterhouseCoopers LLP from 1993 to 2000. Mr. Fairchild served in the U.S. Air Force from 1986 to 1990. He holds a Bachelor of Business Administration in Accounting from The University of Texas at Austin and is a Certified Public Accountant in the state of Texas.

Timothy D. Yang joined Newfield as General Counsel and Corporate Secretary in July 2015. Prior to joining Newfield, Mr. Yang served as Senior Vice President, Land & Legal, General Counsel, Chief Compliance Officer and Secretary of Sabine Oil & Gas Corporation from December 2014 to July 2015. Mr. Yang was previously promoted to Senior Vice President, General Counsel, Chief Compliance Officer and Secretary in February 2013 after beginning service at Sabine in 2011 as Vice President, General Counsel and Secretary. Prior to Sabine, Mr. Yang served as Associate General Counsel and Assistant Corporate Secretary for Eagle Rock Energy Partners, L.P. from 2009 to 2011. His legal experience covers both public and private companies within the energy and investment industries including Invesco Ltd./AIM Investments, Pogo Producing Company and AEI Services LLC. Mr. Yang holds a Bachelor of Arts in Biology from Trinity University, obtained his Juris Doctor from the University of Houston Law Center and is a member of the Texas and Kansas state bar associations.

Matthew R. Vezza began serving as Vice President — Assets following the consolidation of the Company's Mid-Continent business unit in 2016. He was previously promoted to Vice President — Western Region in August of 2015 when the Company's Onshore Gulf Coast and Rocky Mountain business units were combined. He served as Vice President — Rocky Mountains beginning in June of 2014. Mr. Vezza joined Newfield in August 2012 as General Manager of our Rocky Mountains business unit after 16 years with Marathon Oil Company. Mr. Vezza began his career at Marathon in 1996 as a production engineer and then moved through the organization in various technical and managerial roles in Oklahoma, Texas, Louisiana, Colorado and Wyoming. While at Marathon, Mr. Vezza's last position, from August 2009 to August 2012, was serving as Asset Manager - Wyoming. Mr. Vezza is a member of the Society of Petroleum Engineers and holds a Bachelor of Science in Petroleum and Natural Gas Engineering from Penn State University.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for Common Stock

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol "NFX." The following table sets forth, for each of the periods indicated, the high and low reported sales price of our common stock on the NYSE.

	High	Low
2015:		
First Quarter	$36.26	$22.31
Second Quarter	40.27	33.96
Third Quarter	36.77	26.78
Fourth Quarter	41.34	29.88
2016:		
First Quarter	$34.97	$20.84
Second Quarter	44.79	30.88
Third Quarter	47.56	39.25
Fourth Quarter	50.00	37.17
2017:		
First Quarter (through February 16, 2017)	$43.74	$37.95

On February 16, 2017, the last reported sales price of our common stock on the NYSE was $42.14. As of that date, there were 1,444 record holders of our common stock.

Dividends

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indentures governing our 5¾% Senior Notes due 2022, our 5 % Senior Notes due 2024 and our 5 % Senior Notes due 2026 could restrict our ability to pay cash dividends. See "Contractual Obligations" under Item 7 of this report and Note 11, "Debt," to our consolidated financial statements in Item 8 of this report.

Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2016.

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 Number (or Approximate Dollar Value) of Shares that May Yet be Purchased under the Plans or Programs
October 1 — October 31, 2016	4,561	$ 43.35	—	—
November 1 — November 30, 2016	11,932	40.75	—	—
	5,841	46.46	—	—

December 1 — December 31, 2016				
Total	22,334	$ 42.77	—	—

(1) All of the shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards and restricted stock units. These repurchases were not part of a publicly announced program to repurchase shares of our common stock.

See information incorporated by reference in Note 15, "Stock-Based Compensation," to our consolidated financial statements in Item 8 of this report and Item 12 of this report regarding securities authorized for issuance under the Company's equity compensation plans.

Stockholder Return Performance Presentation

The performance presentation below is furnished pursuant to applicable rules of the SEC. As required by these rules, the performance graph was prepared based upon the following assumptions:

- $100 was invested in our common stock, the S&P 500 Index and our peer group on December 31, 2011, at the closing price on such date;
- Investment in our peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of the period; and
- Dividends were reinvested on the relevant payment dates.

Peer Group. Our peer group consists of Bill Barrett Corporation, Carrizo Oil & Gas, Inc., Concho Resources Inc., Chesapeake Energy Corporation, Cimarex Energy Co., Continental Resources Inc., Devon Energy Corporation, Energen Corp., EP Energy Corp., Jones Energy, Marathon Oil Corporation, Matador Resources Company, Noble Energy, Inc., PDC Energy, Pioneer Natural Resources Company, QEP Resources Inc., SM Energy Co., Whiting Petroleum Corporation and WPX Energy Inc.

Comparison of Five-Year Cumulative Total Return

Total Return Analysis	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016
Newfield Exploration Company	$ 100.00	$ 70.98	$ 65.28	$ 71.88	$ 86.30	$ 107.34
S&P 500 Index - Total Returns	100.00	116.00	153.57	174.60	177.01	198.18
Peer Group	100.00	95.94	135.27	107.56	66.83	99.15

Item 6. Selected Financial Data

SELECTED FIVE-YEAR FINANCIAL DATA

The following table shows selected consolidated financial data derived from our consolidated financial statements set forth in Item 8 of this report. The data should be read in conjunction with Items 1 and 2, "Business and Properties," and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this report.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In millions, except per share data)				
Statement of Operations Data:					
Oil, gas and NGL revenues[(1)]	$1,472	$1,557	$2,288	$1,857	$1,562
Income (loss) from continuing operations	(1,230)	(3,362)	650	73	(922)
Net income (loss)	(1,230)	(3,362)	900	147	(1,184)
Earnings (loss) per share:					
Diluted:					
Income (loss) from continuing operations	$(6.36)	$(21.18)	$4.71	$0.39	$(6.85)
Diluted earnings (loss) per share	(6.36)	(21.18)	6.52	0.94	(8.80)
Weighted-average number of shares outstanding for diluted earnings (loss) per share	193	159	138	136	135

Balance Sheet Data (at end of period):					
Total assets	$4,312	$4,768	$9,580	$9,297	$7,884
Long-term debt	2,431	2,467	2,874	3,670	3,017

(1) Continuing operations only (excludes Malaysia).

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are an independent energy company engaged in the exploration, development and production of crude oil, natural gas and natural gas liquids. Our U.S. operations are onshore and focus primarily on large scale, liquids-rich resource plays. Our principal areas of operation are the Anadarko and Arkoma basins of Oklahoma, the Williston Basin of North Dakota and the Uinta Basin of Utah. In addition, we have oil producing assets offshore China.

To maintain and grow our production and cash flows, we must continue to develop existing proved reserves and locate or acquire new oil and natural gas reserves to replace produced reserves. Our revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on our ability to find, acquire and develop oil and natural gas reserves that are economically recoverable. Prices for oil, natural gas and NGLs fluctuate widely and affect the:

- amount of cash flows available for capital investments;
- ability to borrow and raise additional capital; and
- quantity of oil, natural gas and NGLs that we can economically produce.

We achieved many operational, financial and strategic successes in 2016, including:

- increased domestic production 8% over 2015 to 53.3 MMBOE, excluding approximately 5.3 Bcf of natural gas produced and consumed in operations;
- increased net acres in SCOOP and STACK to approximately 400,000 acres at year-end 2016;
- lease operating expense, on a per BOE basis, decreased 20% year over year;
- general and administrative expense, on a per BOE basis, decreased 19% year over year, primarily due to workforce reductions and organizational restructuring;
- acquired additional properties in the Anadarko Basin STACK play for an adjusted purchase price of $476 million, subject to customary post-close adjustments;
- divested substantially all our oil and gas assets in the Maverick and Gulf Coast basins of Texas for approximately $380 million;
- restructured our domestic business to better utilize resources and improve cost efficiencies;
- issued 34.5 million additional shares of common stock through a public equity offering for net proceeds of approximately $776 million. A portion of the proceeds was used to acquire additional properties in the Anadarko Basin STACK play and to repay borrowings under our credit facility and money market lines of credit. The remainder is available for general corporate purposes; and
- increased liquidity to $2.4 billion consisting of a $1.8 billion undrawn credit facility and $580 million of cash and cash equivalents and short-term investments on hand at year end.

Our 2017 business plan is focused on:

- maintain and prioritize liquidity preservation over reserve and production growth;
- allocate the majority of capital to SCOOP and STACK;
- execute select, strategic acquisitions and divestitures; and
- implement a plan to further reduce domestic per unit lease operating costs.

Results of Continuing Operations

Our continuing operations consist of exploration, development and production activities in the United States and China. In January 2017, we signed an agreement, subject to customary regulatory approval, to sell our non-operated interest in the Bohai Bay field in China. See Note 21, "Subsequent Events," to our consolidated financial statements in Item 8 of this report.

Domestic Revenues and Production. Revenues from domestic operations of $1.3 billion for the year ended December 31, 2016 were 3% lower than 2015. The lower revenues were attributable to a 9% decrease in the average crude oil and natural gas realized prices compared to 2015, partially offset by a 4% increase in average NGL realized prices. Increased production reduced the impact of lower commodity prices by $58 million.

Our domestic year over year production increase of 8% was attributable to the Anadarko Basin. Our Anadarko Basin oil, natural gas and NGL production increased by 43%, 36% and 36%, respectively, during 2016. Production in our other domestic basins declined or remained flat as compared to 2015 due to reduced drilling and natural decline in those areas. After adjusting for our STACK properties acquisition in the second quarter of 2016 and our Texas assets sale in the third quarter of 2016 (as discussed in Note 6, "Oil and Gas Properties," to the consolidated financial statements contained in Item 8 of this report), domestic liquids and natural gas production increased 9% and 16%, respectively.

Revenues from domestic operations of $1.3 billion for the year ended December 31, 2015 were 42% lower than 2014. The lower revenues were attributable to a 46% decrease in the average revenue per BOE compared to 2014. Domestic liquids production increased 12% year over year, reducing the impact of lower commodity prices by $236 million.

Our 2015 domestic crude oil production increased 15%, primarily due to doubling our Anadarko Basin oil volumes from 2014 levels. Additionally, Williston Basin and Eagle Ford each experienced year over year oil production increases of 3%. Domestic NGL production increased 4%, while natural gas production decreased 2% from 2014 levels. Adjusted for the sale of Granite Wash assets in the third quarter of 2014 (as discussed in Note 6, "Oil and Gas Properties," to the consolidated financial statements contained in Item 8 of this report), NGL and natural gas production increased 16% and 8%, respectively. NGL production volumes increased in the Anadarko Basin and Williston Basin by 20% and 40%, respectively. Natural gas production in the Anadarko Basin and Williston Basin increased 42% and 20%, respectively.

China Revenues and Production/Liftings. Our revenues from China of $217 million for the year ended December 31, 2016, were 17% lower than 2015. The lower revenues were attributed to a 17% decrease in the 2016 realized crude oil price compared to 2015. Approximately 90% of our 2016 production from China was from the Pearl development. The Pearl development reached peak production during 2015 and was on plateau for most of 2016. We expect declining production from the Pearl development during 2017 and expect to close on the sale of our Bohai Bay assets in mid-2017. See Note 21, "Subsequent Events," to the consolidated financial statements contained in Item 8 of this report.

Our revenues from China were $262 million for the year ended December 31, 2015. Approximately 85% of our 2015 production from China was from the Pearl development, which achieved first oil in the fourth quarter of 2014.

The following table reflects our production/liftings from continuing operations and average realized commodity prices:

	2016	2015	2014
Production/Liftings:			
Domestic:[1]			
Crude oil and condensate (MBbls)	20,972	21,346	18,547
Natural gas (Bcf)	129.9	116.3	118.2
NGLs (MBbls)	10,720	8,553	8,207
Total (MBOE)	53,344	49,277	46,448
China:[2]			
Crude oil and condensate (MBbls)	5,370	5,399	499
Total continuing operations:			
Crude oil and condensate (MBbls)	26,342	26,745	19,046
Natural gas (Bcf)	129.9	116.3	118.2
NGLs (MBbls)	10,720	8,553	8,207
Total (MBOE)	58,714	54,676	46,946
Average Realized Prices:			
Domestic:[3]			
Crude oil and condensate (per Bbl)	$36.39	$39.89	$80.40
Natural gas (per Mcf)	2.18	2.40	4.11
NGLs (per Bbl)	19.05	18.40	32.04
Crude oil equivalent (per BOE)	23.52	26.28	48.41
China:			
Crude oil and condensate (per Bbl)	$40.35	$48.50	$78.52
Total continuing operations:			
Crude oil and condensate (per Bbl)	$37.20	$41.63	$80.35
Natural gas (per Mcf)	2.18	2.40	4.11
NGLs (per Bbl)	19.05	18.40	32.04
Crude oil equivalent (per BOE)	25.06	28.48	48.73

(1) Excludes natural gas produced and consumed in operations of 5.3 Bcf in 2016, 7.7 Bcf in 2015 and 8.5 Bcf in 2014.

(2) Represents our net share of volumes sold regardless of when produced.

(3) Had we included the realized effects of derivative contracts, the domestic average realized prices would have been as follows:

	2016	2015	2014
Crude oil and condensate (per Bbl)	$45.87	$57.48	$80.23
Natural gas (per Mcf)	2.20	3.51	3.81

Operating Expenses.

Year ended December 31, 2016 compared to December 31, 2015

The following table presents information about operating expenses for our continuing operations:

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase	Year Ended December 31,		Percentage Increase
	2016	2015	(Decrease)	2016	2015	(Decrease)
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$3.55	$4.69	(24)%	$189	$231	(18)%
Transportation and processing	5.09	4.29	19%	272	212	28%
Production and other taxes	0.77	0.91	(15)%	41	45	(8)%
Depreciation, depletion and amortization	8.58	15.31	(44)%	458	754	(39)%
General and administrative	3.84	4.80	(20)%	205	237	(13)%
Ceiling test and other impairments	18.04	97.13	(81)%	962	4,786	(80)%
Other	0.38	0.19	100%	20	9	>100%
Total operating expenses	40.25	127.32	(68)%	2,147	6,274	(66)%
China:						
Lease operating	$10.31	$10.07	2%	$55	$54	1%
Production and other taxes	0.15	0.15	—%	1	1	(2)%
Depreciation, depletion and amortization	21.17	30.09	(30)%	114	163	(30)%
General and administrative	1.43	1.31	9%	8	7	9%
Ceiling test impairment	12.30	21.84	(44)%	66	118	(44)%
Other	—	0.21	(100)%	—	1	(100)%
Total operating expenses	45.36	63.67	(29)%	244	344	(29)%
Total Continuing Operations:						
Lease operating	$4.16	$5.22	(20)%	$244	$285	(14)%
Transportation and processing	4.62	3.87	19%	272	212	28%
Production and other taxes	0.72	0.84	(14)%	42	46	(8)%
Depreciation, depletion and amortization	9.74	16.77	(42)%	572	917	(38)%
General and administrative	3.62	4.46	(19)%	213	244	(13)%
Ceiling test and other impairments	17.51	89.69	(80)%	1,028	4,904	(79)%
Other	0.35	0.19	84%	20	10	98%
Total operating expenses	40.72	121.04	(66)%	2,391	6,618	(64)%

Domestic Operations. For the year ended December 31, 2016, total operating expenses per BOE decreased significantly compared to the year ended December 31, 2015. The primary reasons for the decrease follow:

- Total lease operating expenses (LOE) decreased 18% despite an 8% increase in total production due to our focus on cost-reduction initiatives in all basins. On a per BOE basis, lease operating expense was 24% lower due to successful cost reduction efforts combined with our focused growth in the Anadarko Basin, which has lower operating costs than our other basins.
- Transportation and processing expense per BOE increased 19% primarily due to an increase in NGL and natural gas volumes produced of 25% and 12%, respectively. Additionally, oil transportation costs increased due to deficiency fees

in the Uinta Basin (see further discussion below in "Contractual Obligations") and higher utilization of pipelines to transport oil in the STACK play and Williston Basin, which allows us to transport oil to more favorable markets and thus receive a higher net price.

- Production and other taxes decreased 15% per BOE year over year primarily due to our current development activities occurring in areas with lower production tax rates.
- Depreciation, depletion and amortization (DD&A) decreased 44% per BOE primarily due to the impact of ceiling test impairments of $4.8 billion recorded in 2015 and $962 million recorded in the first half of 2016.
- General and administrative expense (G&A) decreased 13%. G&A expenses for both years included capitalized direct internal costs and costs associated with workforce reductions and organizational restructuring. Excluding these items that affect comparability, gross G&A costs decreased 11% year over year, primarily due to cost savings initiatives including a more than 15% reduction of our workforce. The following table presents information regarding G&A expenses for our domestic operations:

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2016	2015		2016	2015	
	(Per BOE)			(In millions)		
G&A expense (net of amounts capitalized)	$3.84	$4.80	(20)%	$205	$237	(13)%
Capitalized direct internal costs	1.31	1.52	(14)%	70	75	(7)%
Gross G&A expense	5.15	6.32	(19)%	275	312	(12)%
Other items affecting comparability:						
Reduction in workforce and restructuring[1]	$(0.53)	$(0.77)	(32)%	$(28)	$(39)	(27)%
SVAP program[2]	—	0.05	(100)%	—	3	(100)%
Total	4.62	5.60	(17)%	247	276	(11)%

(1) Includes severance costs for workforce reductions, as well as office-lease abandonment and other organizational restructuring costs related to the consolidation of our Denver, Houston and Tulsa offices into our headquarters in The Woodlands, Texas. See Note 17, "Restructuring Costs," to our consolidated financial statements in Item 8 of this report for additional details regarding our restructuring activities.

(2) SVAP program decrease is associated with the decrease in the estimated fair value of the liability for our Stockholder Value Appreciation Program (SVAP), which ended December 31, 2015.

- During 2016, we recorded ceiling test impairments of $962 million due to a net decrease in the discounted value of our proved reserves. The decrease primarily resulted from a 15% decrease in crude oil SEC pricing and a 4% decrease in natural gas SEC pricing since December 31, 2015. These commodity price decreases were partially offset by the impact of current service cost reductions on our cash flow estimates.
- Other operating expense increased $11 million primarily due to the settlement of a lawsuit against the Company during the third quarter of 2016. See Note 12, "Commitments and Contingencies," to our consolidated financial statements in Item 8 of this report.

China Operations. The primary components within our operating expenses are as follows:

- Lease operating expense remained flat year over year.
- DD&A expense per BOE decreased 30% primarily due to a reduction of our DD&A rate as a result of the ceiling test impairments during the second half of 2015 and the first half of 2016.
- During 2016, we recorded non-cash ceiling test impairments of $66 million due to a net decrease in the discounted value of our proved reserves. The decrease primarily resulted from a 15% decrease in crude oil SEC pricing since December 31, 2015.

Year ended December 31, 2015 compared to December 31, 2014

The following table presents information about our operating expenses for our continuing operations:

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2015	2014		2015	2014	
	(Per BOE)			(In millions)		
Domestic:						
Lease operating	$4.69	$6.44	(27)%	$231	$299	(23)%
Transportation and processing	4.29	3.74	15%	212	174	22%
Production and other taxes	0.91	2.26	(60)%	45	105	(57)%
Depreciation, depletion and amortization	15.31	18.46	(17)%	754	857	(12)%
General and administrative	4.80	4.78	—%	237	221	7%
Ceiling test and other impairments	97.13	—	100%	4,786	—	100%
Other	0.19	0.53	(64)%	9	25	(63)%
Total operating expenses	127.32	36.21	>100%	6,274	1,681	>100%
China:						
Lease operating	$10.07	$24.05	(58)%	$54	$12	>100%
Production and other taxes	0.15	11.20	(99)%	1	6	(85)%
Depreciation, depletion and amortization	30.09	25.87	16%	163	13	>100%
General and administrative	1.31	1.11	18%	7	1	>100%
Ceiling test impairment	21.84	—	100%	118	—	100%
Other	0.21	—	100%	1	—	100%
Total operating expenses	63.67	62.23	2%	344	32	>100%
Total Continuing Operations:						
Lease operating	$5.22	$6.62	(21)%	$285	$311	(8)%
Transportation and processing	3.87	3.70	5%	212	174	22%
Production and other taxes	0.84	2.36	(64)%	46	111	(59)%
Depreciation, depletion and amortization	16.77	18.53	(9)%	917	870	5%
General and administrative	4.46	4.74	(6)%	244	222	9%
Ceiling test and other impairments	89.69	—	100%	4,904	—	100%
Other	0.19	0.53	(64)%	10	25	(58)%
Total operating expenses	121.04	36.48	>100%	6,618	1,713	>100%

Domestic Operations. For the year ended December 31, 2015, total operating expenses per BOE increased significantly compared to the year ended December 31, 2014. The primary reasons for the increase follow:

- Lease operating expenses decreased 27% on a per BOE basis primarily due to lower service costs and higher production volumes. Service costs declined primarily in the Uinta and Anadarko basins period over period due to our increased focus on cost-reduction initiatives combined with downward service cost pressures in the industry due to lower oil and natural gas prices.
- Transportation and processing expense increased 15% on a per BOE basis primarily due to the increase in combined gas and NGL volumes in SCOOP and STACK, which are subject to higher processing fees related to liquids-rich gas production.

- Production and other taxes on a per BOE basis decreased 60% year over year primarily due to lower revenues, and a higher percent of our 2015 production derived from areas with lower production tax rates. Additional decreases were due to enhanced recovery credits and tax incentives for stripper wells for our Uinta Basin assets, which includes $7 million of credits from prior years. Excluding the impact of these additional tax incentive recoveries, production and other taxes as a percent of total revenue were 4.0% and 4.7% for the years ended December 31, 2015 and 2014, respectively.
- Depreciation, depletion and amortization decreased 17% on a per BOE basis primarily due to the impact of $4.8 billion ceiling test impairments recorded in 2015.
- General and administrative expense increased 7% primarily as a result of reduced capitalization of direct internal costs, workforce reductions, organization restructuring and stock-based compensation programs. Excluding these items that affect comparability, gross G&A costs decreased 15% year over year primarily due to cost savings initiatives including a more than 20% reduction of our workforce. The following table presents information regarding G&A expenses for our domestic operations:

	Unit-of-Production			Total Amount		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2015	2014		2015	2014	
	(Per BOE)			(In millions)		
G&A expense (net of amounts capitalized)	$4.80	$4.78	— %	$237	$221	7 %
Capitalized direct internal costs[1]	1.52	2.90	(48)%	75	135	(45)%
Gross G&A expense	6.32	7.68	(18)%	312	356	(13)%
Other items affecting comparability:						
Reduction in workforce and restructuring[2]	$(0.77)	$—	(100)%	$(39)	$—	(100)%
SVAP program[3]	0.05	(0.71)	>100%	3	(33)	>100%
Total	5.60	6.97	(20)%	276	323	(15)%

(1) Capitalized direct internal costs decrease is consistent with the reduced exploration and development activities in the Uinta, Williston and Maverick basins during 2015.

(2) Includes severance costs for workforce reductions in early 2015, as well as office-lease abandonment and other organizational restructuring costs related to the consolidation of our Denver and Houston offices in 2015 into our headquarters in The Woodlands, Texas. See Note 17, "Restructuring Costs," to our consolidated financial statements in Item 8 of this report for additional details regarding our restructuring activities.

(3) SVAP program decrease is associated with the decrease in the estimated fair value of the liability for our Stockholder Value Appreciation Program (SVAP), which ended December 31, 2015. During 2014, three thresholds were achieved that resulted in payments to employees.

- During 2015, we recorded ceiling test impairments of $4.8 billion due to a net decrease in the discounted value of our proved reserves. The decrease primarily resulted from a 47% decrease in crude oil SEC pricing and a 40% decrease in natural gas SEC pricing since December 31, 2014. These commodity price decreases were partially offset by the impact of service cost reductions on our cash flow estimates. Additionally, during the first quarter of 2015, we recorded a $4 million rig impairment associated with our decision to indefinitely lay down both of our company-owned drilling rigs in the Uinta Basin.
- Other operating expense decreased $16 million primarily due to equipment inventory impairments and legal settlements recorded in 2014.

China Operations. For the year ended December 31, 2015, total operating expenses increased $312 million compared to the year ended December 31, 2014, primarily due to a full year of production activity from our Pearl development and the ceiling test impairments recorded in the third and fourth quarters of 2015. As a result of the different cost structures of our Pearl development and our Bohai Bay field, the 2015 results are not comparable with 2014. The 2015 increase was slightly offset by

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a $5 million decrease in production and other taxes as a new regulation was implemented by the Chinese government in early 2015 resulting in no special levy taxes on production with an actual realized contract price below $65 per barrel.

The Pearl development produced at a rate of 13,000 BOPD (net) from five horizontal wells and one vertical well during the fourth quarter of 2015.

Interest Expense. The following table presents information about interest expense for each of the years ended December 31. Interest expense associated with unproved oil and gas properties is capitalized into oil and gas properties.

	2016	2015	2014
	(In millions)		
Gross interest expense:			
Credit arrangements	$14	$10	$10
Senior notes	140	132	101
Senior subordinated notes	—	21	89
Other	—	1	—
Total gross interest expense	154	164	200
Capitalized interest	(51)	(33)	(53)
Net interest expense	$103	$131	$147

Gross interest expense decreased in 2016 as compared to 2015 due to the April 2015 retirement of our $700 million aggregate principal of 6 % Senior Subordinated Notes due 2020 using the proceeds from the lower interest rate $700 million 5 % Senior Notes due 2026 issued in March 2015. Gross interest expense decreased in 2015 as compared to 2014 due to the fourth quarter of 2014 retirement of our 7 % Senior Subordinated Notes due 2018 and the April 2015 retirement of our 6 % Senior Subordinated Notes due 2020. This decrease was partially offset by the additional interest expense associated with the March 2015 issuance of our $700 million 5 % Senior Notes due 2026. See Note 11, "Debt," to our consolidated financial statements in Item 8 of this report.

Capitalized interest increased in 2016 as compared to 2015 due to an increase in the average amount of unproved oil and gas properties related to unproved properties acquired during the year. Capitalized interest decreased in 2015 as compared to 2014 due to a reduction of the average amount of unproved oil and gas properties coupled with a reduced capitalization rate due to a reduction in our average borrowing rate.

Commodity Derivative Income (Expense). The fluctuations in commodity derivative income (expense) from period to period are due to the volatility of oil and natural gas prices and changes in our outstanding derivative contracts during these periods. The amount of unrealized gain (loss) on derivatives is the result of the change in the total fair value of our derivative positions from the prior year.

The $191 million loss recognized in "Commodity derivative income (expense)" in our 2016 consolidated statement of operations related to our derivative financial instruments is comprised of a $201 million realized gain and a $392 million unrealized loss. The components of the change in the fair value of our net derivative asset (liability) follow:

	Positions Settled in 2016	Positions Settling in 2017 and Thereafter	Total
	(In millions)		
Net derivative asset (liability) at December 31, 2015	$272	$ 95	$367
Change in fair value of settled positions	(71)	—	(71)
Realized settlements	(201)	—	(201)

Change in fair value of outstanding positions	—	(120)	(120)
Total unrealized gain (loss)	(272)	(120)	(392)
Net derivative asset (liability) at December 31, 2016	$—	$ (25)	$(25)

The $259 million gain recognized in "Commodity derivative income (expense)" in our 2015 consolidated statement of operations related to our derivative financial instruments is comprised of a $505 million realized gain and a $246 million unrealized loss. The components of the change in the fair value of our net derivative asset (liability) follow:

	Positions Settled in 2015	Positions Settling in 2016 and Thereafter	Total
	(In millions)		
Net derivative asset (liability) at December 31, 2014	$423	$ 190	$613
Change in fair value of settled positions	82	—	82
Realized settlements	(505)	—	(505)
Change in fair value of outstanding positions	—	177	177
Total unrealized gain (loss)	(423)	177	(246)
Net derivative asset (liability) at December 31, 2015	$—	$ 367	$367

Taxes. Our effective tax rate differs from the federal statutory rate of 35% due to the change in valuation allowances, non-deductible expenses, state income taxes, the differences between international and U.S. federal statutory rates and the impact of taxation of our China earnings in both the U.S and China. Our future effective tax rates may also be impacted by additional ceiling test impairments or other items which generate deferred tax assets, deferred tax asset valuation allowances, and/or reversal of such valuation allowances.

The effective tax rates for the year ended December 31, 2016 and 2015 were (2)% and 32%, respectively. The following table summarizes our tax activity that derives our 2016 effective tax rate.

	Domestic	China	Total
		(In millions)	
Total income (loss) before income taxes	$(1,181)	$ (27)	$(1,208)
U.S. federal statutory tax rate	35 %	35 %	35 %
Tax expense (benefit) at statutory tax rate	(413)	(10)	(423)
State and local income taxes, net of tax effect	—	—	—
Change in valuation allowances	429	29	458
Foreign tax on foreign earnings	—	(7)	(7)
Other	(6)	—	(6)
Total provision (benefit) for income taxes	$10	$ 12	$22
Effective tax rate	(1)%	(44)%	(2)%

See Note 8, "Income Taxes" to our consolidated financial statements in Item 8 of this report for additional disclosures.

Results of Discontinued Operations - Malaysia

During the second quarter of 2013, our business in Malaysia met the criteria for classification as held for sale and was reported as discontinued operations. In February 2014, Newfield International Holdings Inc., a wholly-owned subsidiary of the Company, closed the sale of our Malaysia business to SapuraKencana Petroleum Berhad, a Malaysian public company, for $898 million. See Note 1, "Organization and Summary of Significant Accounting Policies," and Note 20, "Discontinued Operations," to our consolidated financial statements in Item 8 of this report for additional information regarding the sale of our Malaysia business.

Revenues and Liftings. Our 2014 Malaysia revenues were primarily from the sale of crude oil. Substantially all of the crude oil from our offshore Malaysia operations was produced into FPSOs and sold periodically as barge quantities were accumulated. Our production from discontinued operations in 2014 was 822,000 barrels of crude oil (represents our net share of volumes sold regardless of when produced) with an average realized price of $109.86 per barrel. Revenues were recorded when oil was lifted and sold, not when it was produced into FPSOs or onshore storage terminals. For the year ended December 31, 2014, revenues from discontinued operations were $90 million.

Operating Expenses. The following table presents our total operating expenses for discontinued operations.

	Year Ended December 31, 2014	
	Unit-of-Production	Total Amount
	(Per BOE)	(In millions)
Lease operating	$ 13.76	$ 11
Production and other taxes	31.16	25
Depreciation, depletion and amortization	39.30	33
Total operating expenses	84.22	69

Liquidity and Capital Resources

We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our capital budgets (excluding acquisitions) are based upon our estimate of internally generated sources of cash, as well as cash on hand and the available borrowing capacity of our revolving credit facility and money market lines of credit.

Given the uncertainty regarding crude oil prices, our capital spending for 2016 (excluding acquisitions) was reduced from 2015 levels to reduce deficit spending and preserve long-term liquidity.

During 2016, as part of our strategy to optimize long-term liquidity, we issued 34.5 million additional shares of common stock through a public equity offering for net proceeds of approximately $776 million. A portion of the proceeds was used to acquire additional properties in the Anadarko Basin STACK play and to repay borrowings under our credit facility and money market lines of credit. The remainder is available for general corporate purposes. In addition, during 2016 we divested substantially all our oil and gas assets in Texas for approximately $380 million. As a result of the foregoing, we ended the year with $2.4 billion of liquidity consisting of a $1.8 billion undrawn credit facility and $580 million of cash and cash equivalents and short-term investments on hand.

We expect our 2017 budget will be financed through our cash flows from operations and cash on hand. However, given the volatility and uncertainty of commodity prices, we may borrow under our credit facility, sell non-strategic assets or access the public debt and equity markets. Our 2017 capital budget, excluding estimated capitalized interest and direct internal costs of approximately $120 million, is expected to be approximately $1.0 billion, which reflects our current outlook for commodity prices in 2017.

Actual capital expenditure levels may vary significantly due to many factors, including drilling results; oil, natural gas and NGL prices; industry conditions; the prices and availability of goods and services; and the extent to which properties are acquired or non-strategic assets are sold. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions is unpredictable. We believe we have the operational flexibility to react quickly with our capital expenditures to changes in circumstances or fluctuations in our cash flows.

We continuously monitor our liquidity needs, coordinate our capital expenditure program with our expected cash flows and projected debt-repayment schedule, and evaluate our available alternative sources of liquidity, including accessing debt and equity capital markets in light of current and expected economic conditions. We believe that our liquidity position and ability to generate cash flows from our operations will be adequate to fund 2017 operations and continue to meet our other obligations. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Arrangements and Other Financing Activities. In March 2016, we entered into the fifth amendment to our Credit Agreement. This amendment changed certain definitions related to our financial covenants and decreased our interest coverage ratio from 3.0:1.0 to 2.5:1.0. Our borrowing capacity remains at $1.8 billion and the facility maturity date remains June 2020. We incurred approximately $3 million of financing costs related to this amendment, which were included in "Interest expense" on our consolidated statement of operations. We also maintain money market lines of credit of $125 million reduced from $195 million at December 31, 2015.

At December 31, 2016, we had no borrowings under our money market lines of credit, no borrowings outstanding under our revolving credit facility and no letters of credit outstanding under our credit facility. We have no scheduled maturities of senior notes until 2022. For a more detailed description of the terms of our credit arrangements and senior notes, see Note 11, "Debt," to our consolidated financial statements in Item 8 of this report.

Our credit facility has restrictive financial covenants that include the maintenance of a ratio of total debt to book capitalization not to exceed 0.6 to 1.0 and maintenance of a ratio of earnings before gain or loss on the disposition of assets, interest expense, income taxes and certain noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test impairments and goodwill impairments) to interest expense of at least 2.5 to 1.0. At December 31, 2016, we were in compliance with all of our debt covenants under our credit facility and do not foresee this changing in 2017.
As of February 16, 2017, we had no borrowings under our money market lines of credit and no borrowings outstanding under our revolving credit facility.

Working Capital.   Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments as well as the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners. Without the effects of commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital. At December 31, 2016, we had positive working capital of $265 million, primarily due to cash on hand from the sale of our Texas assets, as compared to negative working capital of $22 million at December 31, 2015.

Cash Flows from Operations.   Our primary source of capital and liquidity is cash flows provided by operations, which are primarily affected by the sale of oil, natural gas and NGLs, as well as commodity prices, net of the effects of derivative contract settlements and changes in working capital.

Our net cash flows provided by operations were approximately $826 million in 2016, $1.2 billion in 2015 and $1.4 billion in 2014 (includes $3 million of cash flows provided by our Malaysia discontinued operations). We had no cash flows provided by discontinued operations in 2016 or 2015. The primary drivers of lower operating cash flows in 2016 were lower realized derivative gains, which we expect to continue in 2017, as well as lower revenues as a result of lower commodity prices.

Cash Flows from Investing Activities.   Net cash used in investing activities was $991 million, $1.6 billion and $660 million in 2016, 2015 and 2014, respectively.

During 2016, we:

- reduced capital spending on oil and gas properties as compared to 2015 due to the current economic environment for our industry;
- acquired additional properties in the Anadarko Basin STACK play for $476 million, subject to customary post-close adjustments; and
- divested substantially all our oil and gas assets in Texas for approximately $380 million.

For a more detailed description of the Anadarko Basin acquisition and Texas asset divestiture, see Note 6, "Oil and Gas Properties," to our consolidated financial statements in Item 8 of this report.

During 2015, we reduced capital spending on oil and gas properties by $457 million as compared to 2014 due to the economic environment for our industry. During 2014, capital spending on oil and gas properties was $2.1 billion, and we received net proceeds of $1.4 billion from the sale of our Malaysia business and Granite Wash assets.

Cash Flows from Financing Activities.   Net cash provided by financing activities was $715 million and $380 million in 2016 and 2015, respectively. Net cash used in financing activities was $808 million in 2014.

During 2016, we issued 34.5 million additional shares of common stock through a public equity offering for net proceeds of approximately $776 million.

During 2015, we:

- issued 25.3 million additional shares of common stock through a public equity offering and received net proceeds of approximately $815 million, which were used primarily to repay all borrowings under our credit facility and money market lines of credit; and
- issued $700 million 5 % Senior Notes due 2026 through a public debt offering and received net proceeds of $691 million in March 2015. In April 2015, we used the proceeds and cash on hand to redeem our $700 million aggregate principal of our 6 % Senior Subordinated Notes due 2020.

During 2014, we redeemed our $600 million aggregate principal of Senior Subordinated Notes due 2018 using the proceeds from the sale of our Granite Wash assets.

Restructuring

In April 2015 and May 2016, we announced plans to restructure our organization primarily in response to the current commodity price environment and to improve margins, processes and cost efficiencies in operations. See Note 17, "Restructuring Costs," to our consolidated financial statements in Item 8 of this report for additional details regarding our restructuring activities.

Contractual Obligations

The table below summarizes our significant contractual obligations due by year as of December 31, 2016.

	Total	2017	2018	2019	2020	2021	Thereafter
	(In millions)						
Long-term debt:							
Money market lines of credit	$—	$—	$—	$—	$—	$—	$ —
5¾% Senior Notes due 2022	750	—	—	—	—	—	750
5 % Senior Notes due 2024	1,000	—	—	—	—	—	1,000
5 % Senior Notes due 2026	700	—	—	—	—	—	700
Total long-term debt	2,450	—	—	—	—	—	2,450
Other obligations(1):							
Interest payments	1,045	137	137	137	137	137	360
Asset retirement obligations	156	2	2	20	6	4	122
Operating leases and other(2)	223	101	36	25	20	19	22
Firm transportation	193	74	57	45	10	3	4
Total other obligations	1,617	314	232	227	173	163	508
Total contractual obligations	$4,067	$314	$232	$227	$173	$163	$ 2,958

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(1) Excludes assets and liabilities associated with our derivative contracts, which are dependent on the commodity price at the time of the contract settlement. For a discussion regarding our derivative contracts, see Note 4, "Derivative Financial Instruments," to our consolidated financial statements in Item 8 of this report.

(2) Includes agreements for office space, drilling rigs and other equipment, as well as certain service contracts. The majority of these obligations relate to contracts for office space and drilling rigs and are included at the gross contractual value. Due to our various working interests where the drilling rig contracts will be utilized, it is not feasible to estimate a net contractual obligation. Net payments under these contracts are accounted for as capital additions to our oil and gas properties and could be less than the gross obligation disclosed.

We have crude oil minimum volume delivery commitments that relate to our Uinta Basin production with two Salt Lake City, Utah refiners. One delivery commitment is for approximately 15,000 barrels of oil per day through May 2020. The second commitment is for 20,000 barrels of oil per day through August 2025. In the event that we are unable to meet our crude oil volume delivery commitments, we incur deficiency fees ranging from $3.50 to $6.50 per barrel. During 2016, we incurred $16 million of Uinta Basin deficiency fees. Based on forecasted production levels for 2017, we expect to incur $30 million to $40 million in deficiency fees related to these delivery commitments in

2017. See Items 1 and 2, "Business and Properties" for a description of our production and proved reserves. As of December 31, 2016, our delivery commitments through 2025 were as follows:

	Total	2017	2018	2019	2020	2021	Thereafter
Oil (MBbls)	82,025	12,775	12,775	12,775	9,600	7,300	26,800

Commitments under Joint Operating Agreements. Most of our properties are operated through joint ventures under joint operating or similar agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a "working interest" basis. The joint operating agreement provides remedies to the operator if a non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Oil and Gas Derivatives

We use derivative contracts to manage the variability in cash flows caused by commodity price fluctuations associated with our anticipated future oil and gas production for the next 24 to 36 months. As of December 31, 2016, we had no outstanding derivative contracts related to our NGL production. We do not use derivative instruments for trading purposes.

For a further discussion of our derivative activities, see "Critical Accounting Policies and Estimates — Commodity Derivative Activities" below and "Oil, Natural Gas and NGL Prices" in Item 7A of this report. See the discussion and tables in Note 4, "Derivative Financial Instruments," and Note 5, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open contracts and the estimated fair market value of those contracts as of December 31, 2016.

Between January 1, 2017 and February 16, 2017, we did not enter into additional derivative contracts.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for our judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. See Note 1, "Organization and Summary of Significant Accounting Policies," to our consolidated financial statements in Item 8 of this report for a full description of the critical accounting policies and estimates below, as well as other accounting policies and estimates we make. Below are the most significant policies we apply in preparing our financial statements, some of which are subject to alternative treatments under generally accepted accounting principles. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with the Audit Committee of our Board of Directors.

Oil and Gas Activities.   Two generally accepted accounting methods are available for accounting for oil and gas producing activities — successful efforts and full cost. The most significant differences between these methods are the treatment of exploration costs and the manner in which the carrying values of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed, while these costs are capitalized under the full cost method. Both methods provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is a two-step test that compares the carrying value of the properties to the undiscounted cash flows to assess for impairment. If required, the impairment is the difference between the carrying value of individual oil and gas properties and their estimated fair value using forward-looking prices. Impairment under the full cost method requires an evaluation of the after-tax carrying value of oil and gas properties included in a cost center against the after-tax net present value of future cash flows from the related proved reserves, using SEC pricing, costs in effect at year end and a 10% discount rate.

We use the full cost method of accounting for our oil and gas activities. Our financial position and results of operations would have been significantly different had we used the successful efforts method.

Proved Oil, Natural Gas and NGL Reserves. Our engineering estimates of proved oil, natural gas and NGL reserves directly impact financial accounting estimates, including DD&A expense and the full cost ceiling limitation. Proved oil, natural gas and NGL reserves are the estimated quantities of oil, natural gas and NGL reserves that geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs based on SEC pricing and under period-end economic and operating conditions. The process of estimating quantities of proved reserves is complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors, including development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in commodity prices, operating costs and expected performance from a given reservoir will result in future revisions to our estimated proved reserves quantities. All reserve information in this report is based on estimates prepared by our petroleum engineering staff.

Full Cost Pool. Under the full cost method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits, interest and other internal costs directly attributable to these activities, are capitalized into country-based cost centers. Proceeds from the sale of oil and gas properties are applied as a reduction of the costs in the applicable cost center unless the reduction would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. Future development and abandonment costs are added, and unevaluated costs are withheld from the net costs capitalized in cost centers to represent a full cost pool, which is amortized and assessed for impairment.

Future Development and Abandonment Costs. Future development costs include expected costs to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our gathering systems, production platforms and related structures, and restoration costs of land and seabed. We estimate these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, market demand for equipment, currently available procedures and information from our engineering consultants. Because these costs typically extend many years into the future, estimation is difficult and requires judgments that are subject to revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and abandonment costs annually, or more frequently if circumstances change.

The accounting guidance for future abandonment costs requires that a liability and corresponding long-lived asset for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred. The liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Holding all other factors constant, if our estimate of future development and abandonment costs is revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense. To change our diluted earnings per share by $0.01 for the year ended December 31, 2016, our domestic DD&A rate would need to change by $0.15 per BOE, which would require a change in estimate of our domestic future development and abandonment costs of approximately 4%, or $77 million. Our China DD&A rate would need to change by $1.40 per BOE, which would require a change in estimate of our China future development and abandonment costs of approximately 129%, or $9 million.

Unevaluated Costs Withheld From Amortization.   Costs associated with unevaluated properties are excluded from our full cost pool and from amortization until we have evaluated the properties or impairment is indicated. The costs associated with unevaluated leasehold acreage, related seismic data and capitalized interest and direct internal costs are initially excluded from our full cost pool. Leasehold costs are either transferred to our full cost pool with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Leasehold costs are transferred to our full cost pool to the extent a reduction in value has occurred, or a charge is made against earnings if the costs were incurred in a country for which a reserve base has not been established. Currently, there are no unevaluated properties for our China business.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into our full cost pool involves a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2016, we had a total of $1,238 million of costs excluded from the respective full cost pools, all of which related to our domestic full cost pool. Inclusion of these costs in our domestic full cost pool, without adding any associated reserves, could have resulted in additional ceiling test impairments.

Depreciation, Depletion and Amortization. The full cost pool for each country is amortized using a unit-of-production method based on the cost center's proved oil, natural gas and NGL reserves. Estimated proved reserves are a significant component of the calculation of DD&A expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test impairment. To change our diluted earnings per share by $0.01 for the year ended December 31, 2016, our domestic DD&A rate would need to change by $0.15 per BOE, which would require a change in the estimate of our domestic proved reserves of approximately 2%, or 11 MMBOE. Our China DD&A rate would need to change by $1.40 per BOE, which would require a change in the estimate of our China proved reserves of approximately 10%, or 1 MMBOE.

Full Cost Ceiling. Under the full cost method, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of oil and gas property costs that can be capitalized on our balance sheet. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The ceiling value of oil, natural gas and NGL reserves is calculated based on SEC pricing and costs in effect as of the last day of the quarter. Once recorded, a ceiling test impairment is not reversible even if oil and gas prices increase.

We do not anticipate a ceiling test impairment in either the U.S. or China in the first quarter of 2017, as the current strip prices as of February 16, 2017 are above the current SEC pricing for oil and natural gas. It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating and development costs, upward or downward reserve revisions, reserve additions and tax attributes. Subject to these numerous factors and inherent limitations, it is possible that we could experience additional ceiling test impairments in the future. See Note 6, "Oil and Gas Properties — Ceiling Test Impairments," to our consolidated financial statements in Item 8 of this report.

Allocation of Purchase Price in Business Combinations. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and judgments, the accuracy of this allocation is inherently uncertain and could lead to materially different amounts allocated between proved and unproved oil and gas properties which would result in differences in recognizing depletion and amortization in future periods.

Commodity Derivative Activities. Under accounting rules, we may elect to designate certain derivative contracts that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil and gas production. However, we do not designate any of our derivative contracts as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we have in the past experienced, and are likely in the future to experience non-cash volatility in our reported earnings during periods of commodity price volatility. As of December 31, 2016, we had a net derivative liability of $25 million, of which 59%, based on total contracted volumes, was measured based upon a modified Black-Scholes valuation model and, as such, is classified as a Level 3 fair value measurement. The value of these contracts at their respective settlement dates could be significantly different from the fair value as of December 31, 2016. We periodically validate our valuations using independent third-party quotations. For further discussion of our derivative instruments and activities, see "Oil, Natural Gas and NGL Prices," in Item 7A of this report. Also see Note 4, "Derivative Financial Instruments," and Note 5, "Fair Value Measurements," to our consolidated financial statements in Item 8 of this report for additional information regarding the accounting applicable to our oil and gas derivative contracts, a listing of open contracts and the estimated fair market value of those contracts as of December 31, 2016.

Stock-Based Compensation. We apply a fair value-based method of accounting for stock-based compensation, which requires recognition in the financial statements of the cost of services received in exchange for equity and liability awards. For equity awards, compensation expense is based on the fair value on the grant or modification date and is recognized in our financial statements over the vesting period. We utilize the Black-Scholes option-pricing model to measure the fair value of stock options and a Monte Carlo lattice-based model for our performance- and market-based restricted stock and restricted stock units. We also have cash-settled restricted stock units that are accounted for under the liability method, which requires us to recognize the fair value of each award based on the Company's stock price at the end of each period. See Note 15, "Stock-Based Compensation," to our consolidated financial statements in Item 8 of this report for a full discussion of our stock-based compensation.

Income Taxes. The amount of income taxes recorded by the Company requires significant judgment by management and is reviewed and adjusted routinely based on changes in facts and circumstances. We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements. Utilization of deferred tax assets is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period. Estimates of future taxable income can be significantly affected by changes in oil, gas and NGL prices; estimates of the timing and amount of future production; and estimates of future operating and capital costs. Therefore, no certainty exists that we will be able to fully utilize deferred tax assets. We assess the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize deferred tax assets. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that some portion or all of the related deferred tax benefits will not be realized. Changes in judgment regarding future realizability of deferred tax assets may result in the reversal of all or a portion of the valuation allowance. In the period that determination is made, our net income will benefit from a lower effective tax rate. See Note 8, "Income Taxes," to our consolidated financial statements in Item 8 of this report for a full discussion of income taxes.

New Accounting Requirements

See Note 1, "Organization and Summary of Significant Accounting Policies," to our consolidated financial statements in Item 8 of this report for a discussion of new accounting requirements.

Regulation

Exploration, development, production and the sale of oil, natural gas and NGLs are subject to extensive federal, state, provincial, tribal, local and international regulations. An overview of these regulations is set forth in Items 1 and 2, "Business and Properties — Regulation." We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. See the discussion under the caption "We are subject to complex laws and regulatory actions that can affect the cost, manner, feasibility or timing of doing business," in Item 1A of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from changes in oil, natural gas and NGL prices, interest rates and foreign currency exchange rates as discussed below.

Oil, Natural Gas and NGL Prices

Our decision on the quantity and price at which we choose to enter into derivative contracts is based in part on our view of current and future market conditions. While the use of derivative contracts can limit or reduce the downside risk of adverse price movements, their use also may limit future benefits from favorable price movements. In addition, the use of derivative contracts may involve basis risk. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative contracts also involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2016, 10 of our 16 counterparties accounted for approximately 85% of our contracted volumes with the largest counterparty accounting for approximately 14%.

As of December 31, 2016, 12,753 MBbls of our expected 2017 crude oil production were protected against price volatility using collars and swaps, over 51% which have associated sold puts. The sold puts limit our downward price protection below the weighted average price of our sold puts of $73.83 per barrel. If the market price remains below $73.83 per barrel, we receive the market price for our associated production plus the difference between our sold puts and the associated floors or fixed-price swaps, which averages $15.06 per barrel. For 6,548 MBbls of our 2017 volumes, we have locked in an average minimum premium of $13.54 over the market price using purchased calls. The weighted average strike price of the purchased calls approximates the weighted average strike price of the sold puts, thereby effectively locking in the value. For further discussion of our derivative instruments and activities, see Note 4, "Derivative Financial Instruments," to our consolidated financial statements in Item 8 of this report.

Interest Rates

At December 31, 2016, our debt included:

	Fixed Rate Debt	Variable Rate Debt
	(In millions)	
Revolving credit facility and money market lines of credit	$—	$ —
5¾% Senior Notes due 2022	750	—
5 % Senior Notes due 2024	1,000	—
5 % Senior Notes due 2026	700	—
	$2,450	$ —

We consider our interest rate exposure to be minimal because 100% of our obligations were at fixed rates as of December 31, 2016. A 10% increase in LIBOR would not impact our interest costs on debt outstanding at December 31, 2016, but would decrease the fair value of our outstanding debt, as well as increase interest costs associated with future debt issuances or borrowings under our revolving credit facility and money market lines of credit.

Foreign Currency Exchange Rates

The functional currency for our China operations is the U.S. dollar. To the extent that business transactions in a foreign country are not denominated in the U.S. dollar, we are exposed to foreign currency exchange risk. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts related to foreign currencies at December 31, 2016.

Item 8. Financial Statements and Supplementary Data

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our Company's management, including the Chief Executive Officer and the Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our internal control over financial reporting includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on our evaluation under the framework in Internal Control — Integrated Framework (2013), the management of our Company concluded that our internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

Lee K. Boothby	Lawrence S. Massaro
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

The Woodlands, Texas
February 21, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Newfield Exploration Company:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, of comprehensive income, of stockholders’ equity and of cash flows present fairly, in all material respects, the financial position of Newfield Exploration Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Houston, Texas
February 21, 2017

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEET
(In millions, except share data)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$555	$5
Short-term investments	25	—
Accounts receivable, net	232	262
Inventories	16	34
Derivative assets	75	284
Other current assets	46	40
Total current assets	949	625
Oil and gas properties, net — full cost method ($1,238 and $780 were excluded from amortization at December 31, 2016 and 2015, respectively)	3,140	3,819
Other property and equipment, net	167	172
Derivative assets	—	105
Long-term investments	19	20
Restricted cash	25	13
Other assets	12	14
Total assets	$4,312	$4,768
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$33	$41
Accrued liabilities	498	533
Advances from joint owners	54	58
Asset retirement obligations	2	2
Derivative liabilities	97	13
Total current liabilities	684	647
Other liabilities	63	48
Derivative liabilities	3	9
Long-term debt	2,431	2,467
Asset retirement obligations	154	192
Deferred taxes	39	26
Total long-term liabilities	2,690	2,742
Commitments and contingencies (Note 12)		
Stockholders' equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)	—	—
Common stock ($0.01 par value, 300,000,000 shares authorized at December 31, 2016 and 2015; 200,150,392 and 164,102,786 shares issued at December 31, 2016 and 2015, respectively)	2	2
Additional paid-in capital	3,247	2,436
Treasury stock (at cost, 1,195,809 and 612,469 shares at December 31, 2016 and 2015, respectively)	(44)	(22)
Accumulated other comprehensive income (loss)	(2)	(2)
Retained earnings (deficit)	(2,265)	(1,035)
Total stockholders' equity	938	1,379
Total liabilities and stockholders' equity	$4,312	$4,768

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY
CONSOLIDATED STATEMENT OF OPERATIONS
(In millions, except per share data)

	Year Ended December 31,		
	2016	2015	2014
Oil, gas and NGL revenues	$1,472	$1,557	$2,288
Operating expenses:			
Lease operating	244	285	311
Transportation and processing	272	212	174
Production and other taxes	42	46	111
Depreciation, depletion and amortization	572	917	870
General and administrative	213	244	222
Ceiling test and other impairments	1,028	4,904	—
Other	20	10	25
Total operating expenses	2,391	6,618	1,713
Income (loss) from operations	(919)	(5,061)	575
Other income (expense):			
Interest expense	(154)	(164)	(200)
Capitalized interest	51	33	53
Commodity derivative income (expense)	(191)	259	610
Other, net			