CABOT OIL & GAS CORP
Form 10-K
February 27, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
Commission file number 1-10447
CABOT OIL & GAS CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	04-3072771
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas 77024
(Address of principal executive offices including ZIP code)

(281) 589-4600
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.10 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 ý No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý
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 and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o
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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K o.
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 ý	Accelerated filer o	Non-accelerated filer (Do not check if a smaller reporting company) o	Smaller reporting company o

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

The aggregate market value of Common Stock, par value $.10 per share ("Common Stock"), held by non-affiliates as of the last business day of registrant's most recently completed second fiscal quarter (based upon the closing sales price on the New York Stock Exchange on June 30, 2016) was approximately $11.8 billion.

As of February 17, 2017, there were 475,138,587 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 3, 2017 are incorporated by reference into Part III of this report.

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FORWARD-LOOKING INFORMATION

The statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could," "will" and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and crude oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches and other factors detailed herein and in our other Securities and Exchange Commission filings. See "Risk Factors" in Item 1A for additional information about these risks and uncertainties. Many of these risks are difficult to predict and beyond our controls. Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, we can give no assurance that they will prove to have been correct. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and included within this Annual Report on Form 10-K:

Abbreviations

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

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent.

Btu. One British thermal unit.

Dth. One million British thermal units.

Mbbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent.

Mmbbls. One million barrels of oil or other liquid hydrocarbons.

Mmbtu. One million British thermal units.

Mmcf. One million cubic feet of natural gas.

Mmcfe. One million cubic feet of natural gas equivalent.

NGL. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

Definitions

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Conventional play. A term used in the oil and gas industry to refer to an area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps utilizing conventional recovery methods.

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

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Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

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.

Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Dry hole. Exploratory or development well that does not produce oil or gas in commercial quantities.

Exploitation activities. The process of the recovery of fluids from reservoirs and drilling and development of oil and gas reserves.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (i) costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs, (ii) costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records, (iii) dry hole contributions and bottom hole contributions, (iv) costs of drilling and equipping exploratory wells, and (v) costs of drilling exploratory-type stratigraphic test wells.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, or a service well.

Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geological barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

Gross acres. The total acres in which a working interest is owned.

Gross wells. The total wells in which a working interest is owned.

Net acres. The number of acres an owner has out of a particular number of gross acres. An owner who has a 30% working interest in 100 acres owns 30 net acres.

Net wells. The percentage ownership interest in a well than an owner has based on the working interest. An owner who has a 30% working interest in a well owns a 0.30 net well.

Oil. Crude oil and condensate.

Operator. The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

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Play. A geographic area with potential oil and gas reserves.

Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely not to be recovered.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities, which become part of the cost of oil and gas produced.

Proved properties. Properties with proved reserves.

Proved reserves. Proved reserves are those quantities, 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 and operating methods 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 hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reliable technology. A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonable certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

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

Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Royalty interest. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowners' royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud.

Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at

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year-end), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

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

Undeveloped reserves.   Undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties.   Properties with no proved reserves.

Working interest.   An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

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PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Cabot Oil & Gas Corporation is an independent oil and gas company engaged in the development, exploitation and exploration of oil and gas properties. Our assets are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. We operate in one segment, natural gas and oil development, exploitation, exploration and production, in the continental United States. We have offices located in Houston, Texas and Pittsburgh, Pennsylvania.

STRATEGY

Our objective is to enhance shareholder value over the long-term through consistent growth in production and reserves, even in the current commodity price environment. We believe this is attainable by employing disciplined management of our balance sheet and our operations and remaining focused on our core asset base, which offers a strategic advantage. Key components of our business strategy include:

Disciplined Capital Spending Focused on Organic Projects. We allocate our capital program to economic projects expected to generate the highest returns, maximize our production levels and add to our reserve growth. Our capital program is developed with the expectation of being fully funded through operating cash flows, with any shortfalls funded primarily by cash on hand and/or borrowings under our revolving credit facility. While we consider various growth opportunities, including strategic acquisitions, our primary focus is organic growth through drilling our core areas of operation where we believe we can exploit our extensive inventory of low-cost, repeatable drilling opportunities. The price we expect to receive for our production is a critical factor in the capital investments we make in order to achieve the greatest economic benefit from the development our properties.

Low Cost Structure. Our operations are focused on select unconventional plays with significant resource potential that allow us to add and produce reserves at a low cost. We have developed sizable, contiguous acreage positions in our core operating areas and believe the concentration of our assets allows us to further reduce costs through economies of scale. We continue to optimize drilling and completion efficiencies using multi-well pad drilling, increasing frac stages and drilling longer lateral wells in our core operating areas, resulting in additional cost savings. Furthermore, since we operate in a limited number of geographic areas, we believe we can leverage our technical expertise in these areas to achieve further cost reductions through operational efficiencies. We also operate a majority of our properties, which allows us to more effectively manage all elements of our cost structure.

Conservative Financial Position and Financial Flexibility. We believe the prudent management of our balance sheet and the active management of commodity price risk allows us the financial flexibility to provide continued production and reserve growth over time, even in periods of depressed commodity prices. We utilize derivative contracts to manage commodity price risk and to provide a level of cash flow predictability. In the event we experience a lower than anticipated commodity price environment, we believe that we have the flexibility to supplement the funding of our capital program with cash on hand, borrowings under our revolving credit facility, select asset sales, access to capital markets or, depending on the specific circumstances, reductions to our overall level of activity.

Pursue Strategic Marketing and Transportation Agreements to Maximize Cash Flows and Diversify Risk. We continue to pursue opportunities to maximize our cash flows and diversify our market and customer risk by securing strategic long-term firm transportation and sales contracts in close proximity to our core area of operations.

2017 OUTLOOK

Our 2017 drilling program includes approximately $650.0 million in capital expenditures and approximately $70.0 million in expected contributions to our equity method investments. We expect to fund these expenditures with existing cash, operating cash flow and, if required, borrowings under our revolving credit facility. See Note 4 of the Notes to the Consolidated Financial Statements for further details regarding our equity method investments in Constitution Pipeline Company, LLC (Constitution) and Meade Pipeline Co LLC (Meade).

In 2017, we plan to drill 95 gross wells (90.0 net) and complete 95 gross wells (90.0 net), of which 51 gross wells (45.0 net) were drilled but uncompleted in prior years. We allocate our planned program for capital expenditures among our various operating areas based on market conditions, return expectations, availability of services and human resources. We will continue to assess the natural gas and crude oil price environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

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As a result of higher expected natural gas and crude oil prices, we increased our budgeted capital expenditures compared to 2016. We plan to operate an average of approximately 3.0 rigs in 2017, an increase from an average of approximately 1.4 rigs in 2016. During 2016, we strategically curtailed production levels in the Marcellus Shale due to lower price realizations in the region; however, we expect to increase Marcellus Shale production during 2017.

DESCRIPTION OF PROPERTIES

Our exploration, development and production operations are primarily concentrated in two unconventional plays—the Marcellus Shale in northeast Pennsylvania and the Eagle Ford Shale in south Texas. We also have operations in various other conventional and unconventional plays throughout the continental United States.

Marcellus Shale

Our Marcellus Shale properties represent our largest operating and growth area in terms of reserves, production and capital investment. Our properties are principally located in Susquehanna County, Pennsylvania, where we currently hold approximately 179,000 net acres in the dry gas window of the play. Our 2016 net production in the Marcellus Shale was 581.9 Bcfe, representing approximately 93% of our total equivalent production for the year. As of December 31, 2016, we had a total of 553.0 net wells in the Marcellus Shale, of which approximately 99% are operated by us.

During 2016, we invested $266.1 million in the Marcellus Shale and drilled or participated in drilling 29.0 net wells, completed 63.0 net wells and turned in line 52.0 net wells. As of December 31, 2016, we had 26.2 net wells that were either in the completion stage or waiting on completion or connection to a pipeline. We exited 2016 with two drilling rigs operating in the play and plan to exit 2017 with two rigs operating.

Eagle Ford Shale

Our properties in the Eagle Ford Shale are principally located in Atascosa, Frio and La Salle Counties, Texas, where we hold approximately 84,000 net acres in the oil window of the play. In 2016, our net crude oil/condensate/NGL and natural gas production from the Eagle Ford Shale was 3,819 Mbbl and 2.5 Bcf, respectively, or 25.5 Bcfe, representing approximately 4% of our total equivalent production. As of December 31, 2016, we had a total of 229.3 net wells in the Eagle Ford, of which approximately 90% are operated by us.

During 2016, we invested $91.8 million in the Eagle Ford Shale and drilled or participated in drilling 9.0 net wells, completed 13.0 net wells and turned in line 13.0 net wells. As of December 31, 2016, we had 19.0 net wells that were waiting on completion. We exited 2016 with one drilling rig operating in the play and plan to exit 2017 with one rig operating.

Other Properties

In addition to our core unconventional resource plays, we also operate or participate in other conventional and unconventional plays throughout the continental United States, including the Devonian Shale, Big Lime, Weir and Berea formations in West Virginia; the Haynesville, Bossier, and James Lime formations in east Texas; and the Utica Shale in Pennsylvania.

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems, made up of approximately 3,100 miles of pipeline with interconnects to three interstate transmission systems, four local distribution companies and numerous end users. The majority of our pipeline infrastructure is located in West Virginia and is regulated by the Federal Energy Regulatory Commission (FERC) for interstate transportation service and the West Virginia Public Service Commission (WVPSC) for intrastate transportation service. As such, the transportation rates and terms of service of our pipeline subsidiary, Cranberry Pipeline Corporation, are subject to the rules and regulations of the FERC and the WVPSC. Our natural gas gathering and transmission pipeline systems in West Virginia enable us to connect new wells quickly and transport natural gas from the wellhead directly to interstate pipelines, local distribution companies and industrial end users. Control of our gathering and transmission pipeline systems also enables us to purchase, transport and sell natural gas produced by third parties. In addition, we can engage in development drilling without relying upon third parties to transport our natural gas and incur only the incremental costs of pipeline and compressor additions to our system.

We also have two natural gas storage fields located in West Virginia with a combined working capacity of approximately 4 Bcf. We use these storage fields to take advantage of the seasonal variations in the demand for natural gas typically associated with winter natural gas sales, while maintaining production at a nearly constant rate throughout the year. The pipeline systems and storage fields are fully integrated with our operations in West Virginia.

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ACQUISITIONS

In December 2014, we completed the acquisition of certain proved and unproved oil and gas properties located in the Eagle Ford Shale in south Texas for $30.5 million. Total cash consideration paid was $29.9 million, which reflects the impact of customary purchase price adjustments and acquisition costs.

In October 2014, we purchased certain proved and unproved oil and gas properties located in the Eagle Ford Shale in south Texas for $210.0 million. Total cash consideration paid at closing was $185.2 million, which reflects the impact of customary purchase price adjustments and acquisition costs. In April 2015, we completed the acquisition of the remaining oil and gas properties for which the seller was unable to obtain consents at closing for $16.0 million.

DIVESTITURES

In February 2016, we sold certain proved and unproved oil and gas properties in east Texas to a third party for $56.4 million and recognized a $0.5 million gain on sale of assets.

In October 2014, we sold certain proved and unproved oil and gas properties in east Texas to a third party for $44.3 million and recognized a $19.9 million gain on sale of assets.

In December 2013, we sold certain proved and unproved oil and gas properties located in the Oklahoma and Texas panhandles to Chaparral Energy, L.L.C. for $160.0 million and recognized a $19.4 million gain on sale of assets. We also sold certain proved and unproved oil and gas properties located in Oklahoma, Texas and Kansas to a third party for $123.4 million and recognized a $17.5 million loss on sale of assets.

In 2013, we sold various other proved and unproved oil and gas properties for $44.3 million and recognized an aggregate net gain of $19.5 million.

In 2012, we sold certain unproved oil and gas properties and other assets for $169.3 million and recognized an aggregate net gain of $50.6 million.

MARKETING

Substantially all of our natural gas is sold at market sensitive prices under both long-term and short-term sales contracts and is subject to seasonal price swings. The principal markets for our natural gas are in the northeastern United States where we sell natural gas to industrial customers, local distribution companies, gas marketers and power generation facilities.

We also incur transportation and gathering expenses to move our natural gas production from the wellhead to our principal markets in the United States. The majority of our natural gas production is transported on third-party gathering systems and interstate pipelines where we have long-term contractual capacity arrangements or use purchaser-owned capacity under both long-term and short-term sales contracts.

To date, we have not experienced significant difficulty in transporting or marketing our natural gas production as it becomes available; however, there is no assurance that we will always be able to transport and market all of our production.

Our crude oil is sold at market sensitive prices under long-term sales contracts. The principal markets for our oil are in the south Texas refining region where we can market to refineries and oil pipeline customers.

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell natural gas. We believe we will have sufficient production quantities to meet substantially all of our commitments, but may be required to purchase natural gas from third parties to satisfy shortfalls should they occur.

A summary of our firm sales commitments as of December 31, 2016 are set forth in the table below:

	Natural Gas (Bcfe)
2017	116.9
2018	294.0
2019	614.8
2020	614.8
2021	575.0

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We utilize a part of our firm transportation capacity to deliver natural gas under the majority of these firm sales contracts and have entered into numerous agreements for transportation of our production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms. However, we do not believe we have a financial commitment due based on our current proved reserves and production levels from which we can fulfill these obligations.

RISK MANAGEMENT

From time to time, we use derivative financial instruments to manage price risk associated with our natural gas and crude oil production. While there are many different types of derivatives available, we generally utilize collar, swap and basis swap agreements designed to manage price risk more effectively. The collar arrangements are a combination of put and call options used to establish floor and ceiling prices for a fixed volume of natural gas or crude oil production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The swap agreements call for payments to, or receipts from, counterparties based on whether the index price for the period is greater or less than the fixed price established for the particular period under the swap agreement.

During 2016, natural gas swaps covered 52.0 Bcf, or 9%, of natural gas production at a weighted-average price of $2.51 per Mcf. Crude oil collars with floor prices of $38.00 per Bbl and ceiling prices ranging from $47.10 to $47.50 per Bbl covered 1.4 Mmbbl, or 34%, of crude oil production at a weighted-average price of $45.61 per Bbl.

As of December 31, 2016, we had the following outstanding commodity derivatives:

				Collars					
				Floor		Ceiling		Swaps	Basis Swaps
Type of Contract	Volume		Contract Period	Range	Weighted-Average	Range	Weighted-Average	Weighted-Average	Weighted-Average
Natural gas	35.5	Bcf	Jan. 2017 - Dec. 2017					$ 3.12	
Natural gas	16.2	Bcf	Feb. 2017 - Dec. 2017					$ 3.46	
Natural gas	35.5	Bcf	Jan. 2017 - Dec. 2017	$—	$ 3.09	$3.42-$3.45	$ 3.43		
Natural gas	21.3	Bcf	Jan. 2018 - Dec. 2019						$ 0.42
Crude oil	1.8	Mmbbl	Jan. 2017 - Dec. 2017	$—	$ 50.00	$56.25-$56.50	$ 56.39		

In the table above, natural gas prices are stated per Mcf and crude oil prices are stated per barrel.

While we have hedged a portion of our expected natural gas and crude oil production for 2017 and beyond, any unhedged production is directly exposed to the volatility in natural gas and crude oil market prices, whether favorable or unfavorable. We will continue to evaluate the benefit of using derivatives in the future. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures about Market Risk" for further discussion related to our use of derivatives.

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RESERVES

The following table presents our estimated proved reserves for the periods indicated:

	December 31,		
	2016	2015	2014
Natural Gas (Bcf)			
Proved developed reserves	5,500	4,676	4,339
Proved undeveloped reserves(1)	2,781	3,180	2,743
	8,281	7,856	7,082
Crude Oil & NGLs (Mbbl)(2)			
Proved developed reserves	20,442	25,586	27,221
Proved undeveloped reserves(1)	28,730	30,144	25,915
	49,172	55,730	53,136
Natural gas equivalent (Bcfe)(3)	8,576	8,190	7,401
Reserve life index (in years)(4)	13.7	13.6	13.9

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(1) Proved undeveloped reserves for 2016, 2015 and 2014 include reserves drilled but uncompleted of 488.7 Bcfe, 937.4 Bcfe and 501.1 Bcfe, respectively.

(2) NGL reserves were less than 1.0% of our total proved equivalent reserves for 2016, 2015 and 2014, and 13.6%, 16.1% and 13.5% of our proved crude oil and NGL reserves for 2016, 2015 and 2014, respectively.

(3) Natural gas equivalents are determined using a ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or NGLs.

(4) Reserve life index is equal to year-end proved reserves divided by annual production for the years ended December 31, 2016, 2015 and 2014, respectively.

Our proved reserves totaled approximately 8,576 Bcfe at December 31, 2016, of which 97% were natural gas. This reserve level was up by 5% from 8,190 Bcfe at December 31, 2015. In 2016, we added 683.9 Bcfe of proved reserves through extensions, discoveries and other additions, primarily due to the positive results from our drilling and completion program in the Dimock field in northeast Pennsylvania. We also had a net upward revision of 370.1 Bcfe, which was primarily due to an upward performance revision of 658.7 Bcfe associated with positive drilling results in our Dimock field in northeast Pennsylvania, partially offset by a downward revisions of 246.0 Bcfe associated with proved undeveloped (PUD) reserves reclassifications as a result of the five year limitation and 42.6 Bcfe associated with lower commodity prices. In 2016, we produced 627.1 Bcfe.

Our reserves are sensitive to natural gas and crude oil prices and their effect on the economic productive life of producing properties. Our reserves are based on the 12-month average natural gas, crude oil and NGL index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during the year. Increases in commodity prices may result in a longer economic productive life of a property or result in more economically viable proved undeveloped reserves to be recognized. Decreases in prices may result in negative impacts of this nature.

For additional information regarding estimates of proved reserves, the audit of such estimates by Miller and Lents, Ltd. (Miller and Lents) and other information about our reserves, including the risks inherent in our estimates of proved reserves, see the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8 and “Risk Factors-Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated” in Item 1A.

Technologies Used In Reserves Estimates

We utilize various traditional methods to estimate our natural gas, crude oil and NGL reserves, including decline curve extrapolations, material balance calculations, volumetric calculations and analogies, and in some cases a combination of these methods. In addition, at times we may use seismic interpretations to confirm continuity of a formation in combination with traditional technologies; however, seismic interpretations are not used in the volumetric computation.

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Internal Control

Our Vice President, Engineering and Technology is the technical person responsible for our internal reserves estimation process and provides oversight of our corporate reservoir engineering department, which consists of three engineers, and the annual audit of our year-end reserves by Miller and Lents. He has a Bachelor of Science degree in Chemical Engineering, specializing in petroleum engineering, and over 34 years of industry experience with positions of increasing responsibility in operations, engineering and evaluations. He has worked in the area of reserves and reservoir engineering for 25 years and is a member of the Society of Petroleum Engineers.

Our reserves estimation process is coordinated by our corporate reservoir engineering department. Reserve information, including models and other technical data, are stored on secured databases on our network. Certain non-technical inputs used in the reserves estimation process, including commodity prices, production and development costs and ownership percentages, are obtained by other departments and are subject to testing as part of our annual internal control process. We also engage Miller and Lents, independent petroleum engineers, to perform an independent audit of our estimated proved reserves. Upon completion of the process, the estimated reserves are presented to senior management.

Miller and Lents made independent estimates for 100% of our proved reserves estimates and concluded, in their judgment, we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues. Further, Miller and Lents has concluded (1) the reserves estimation methods employed by us were appropriate, and our classification of such reserves was appropriate to the relevant SEC reserve definitions, (2) our reserves estimation processes were comprehensive and of sufficient depth, (3) the data upon which we relied were adequate and of sufficient quality, and (4) the results of our estimates and projections are, in the aggregate, reasonable. A copy of the audit letter by Miller and Lents dated January 23, 2017, has been filed as an exhibit to this Form 10-K.

Qualifications of Third Party Engineers

The technical person primarily responsible for the audit of our reserves estimates at Miller and Lents meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Miller and Lents is an independent firm of petroleum engineers, geologists, geophysicists, and petro physicists; they do not own an interest in our properties and are not retained on a contingent fee basis.

Proved Undeveloped Reserves

At December 31, 2016 we had 2,953.3 Bcfe of PUD reserves associated with future development costs of $1.5 billion, which represents a decrease of 407.9 Bcfe compared to December 31, 2015. Approximately 94% of our PUD reserves are located in Susquehanna County, Pennsylvania. We expect to complete approximately 99% of our PUD reserves associated with drilled but uncompleted wells by the end of 2017. Future development plans are reflective of the expected increase in commodity prices and have been established based on cash on hand, expected available cash flows from operations and availability under our revolving credit facility. As of December 31, 2016, all PUD reserves are expected to be drilled and completed within five years of initial disclosure of these reserves.

The following table is a reconciliation of the change in our PUD reserves (Bcfe):

	Year Ended December 31, 2016
Balance at beginning of period	3,361.2
Transfers to proved developed	(1,215.5)
Additions	583.7
Revision of prior estimates	223.9
Balance at end of period	2,953.3

Changes in PUD reserves that occurred during the year were due to:

- transfer of 1,215.5 Bcfe from PUD to proved developed reserves based on total capital expenditures of $211.1 million during 2016;

- new PUD reserve additions of 583.7 Bcfe primarily in the Dimock field in northeast Pennsylvania; and

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- positive PUD reserve revisions of 223.9 Bcfe resulting from positive performance revisions of 515.9 Bcfe associated with the drilling of longer lateral wells and completing more frac stages in our Dimock field in northeast Pennsylvania, partially offset by downward revisions of 246.0 Bcfe associated with PUD reclassifications as a result of the five year limitation and negative price revisions of 46.0 Bcfe.

PRODUCTION, SALES PRICE AND PRODUCTION COSTS

The following table presents historical information about our production volumes for natural gas and oil (including NGLs), average natural gas and crude oil sales prices, and average production costs per equivalent, including our Dimock field located in northeast Pennsylvania, which represents more than 15% of our total proved reserves:

	Year Ended December 31,		
	2016	2015	2014
Production Volumes			
Natural gas (Bcf)			
Dimock field	581.9	540.8	479.8
Total	600.4	566.0	508.0
Oil (Mbbl)(1)			
Total	4,454	6,096	3,961
Equivalents (Bcfe)			
Dimock field	581.9	540.8	479.8
Total	627.1	602.5	531.8
Natural Gas Average Sales Price ($/Mcf)			
Dimock field	$1.69	$1.78	$3.37
Total (excluding realized impact of derivative settlements)	$1.70	$1.81	$3.41
Total (including realized impact of derivative settlements)	$1.70	$2.15	$3.28
Oil Average Sales Price ($/Bbl)			
Total (excluding realized impact of derivative settlements)	$37.65	$45.72	$87.65
Total (including realized impact of derivative settlements)	$37.30	$45.72	$88.50
Average Production Costs ($/Mcfe)			
Dimock field	$0.03	$0.04	$0.07
Total	$0.11	$0.18	$0.22

(1) Includes NGLs which represent less than 1.0% of our equivalent production for all years presented and 9.9%, 11.0%, and 9.4% of our oil production for the years ended December 31, 2016, 2015 and 2014, respectively.

ACREAGE

Our interest in both developed and undeveloped properties is primarily in the form of leasehold interests held under customary mineral leases. These leases provide us the right to develop oil and/or natural gas on the properties. Their primary terms range in length from approximately three to 10 years. These properties are held for longer periods if production is established.

The following table summarizes our gross and net developed and undeveloped leasehold and mineral fee acreage at December 31, 2016:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Leasehold acreage	973,863	861,370	420,018	328,943	1,393,881	1,190,313
Mineral fee acreage	151,440	130,387	61,844	52,276	213,284	182,663
Total	1,125,303	991,757	481,862	381,219	1,607,165	1,372,976

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Total Net Undeveloped Acreage Expiration

In the event that production is not established or we take no action to extend or renew the terms of our leases, our net undeveloped acreage that will expire over the next three years as of December 31, 2016 is 78,174, 34,926 and 34,306 for the years ending December 31, 2017, 2018 and 2019, respectively.

We expect to retain substantially all of our expiring acreage either through drilling activities, renewal of the expiring leases or through the exercise of extension options. As of December 31, 2016, approximately 29% of our expiring acreage disclosed above is located in our core areas of operation where we currently expect to continue development activities and/or extend the lease terms.

WELL SUMMARY

The following table presents our ownership in productive natural gas and crude oil wells at December 31, 2016. This summary includes natural gas and crude oil wells in which we have a working interest:

	Gross	Net
Natural gas	3,920	3,623.9
Crude oil	292	240.2
Total[(1)]	4,212	3,864.1

(1) Total percentage of gross operated wells is 93.5%.

DRILLING ACTIVITY

We drilled and completed wells or participated in the drilling and completion of wells as indicated in the table below. The information below should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	76	76.0	106	97.85	173	150.2
Dry	—	—	—	—	—	—
Exploratory Wells						
Productive	—	—	1	1.0	—	—
Dry	—	—	—	—	1	1.0
Total	76	76.0	107	98.9	174	151.2
Acquired Wells	—	—	1	1.0	26	23.7

During the year ended December 31, 2016, we completed 62 gross wells (62.0 net) that were drilled in prior years.

The following table sets forth information about wells for which drilling was in progress or which were drilled but uncompleted at December 31, 2016, which are not included in the above table:

	Drilling In Progress		Drilled But Uncompleted	
	Gross	Net	Gross	Net
Development wells	4	4.0	51	45.2
Exploratory wells	1	1.0	—	—
Total	5	5.0	51	45.2

OTHER BUSINESS MATTERS

Title to Properties

We believe that we have satisfactory title to 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, ordinary course liens incidental to operating agreements and for current taxes or development obligations under oil and gas leases. As is customary in the industry in the case of undeveloped properties, preliminary investigations of record title are made at the time of lease acquisition. Complete investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Competition

The oil and gas industry is highly competitive and we experience strong competition in our primary producing areas. We primarily compete with integrated, independent and other energy companies for the sale and transportation of our oil and natural gas production to marketing companies and end users. Furthermore, the oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial and residential consumers. Many of these competitors have greater financial, technical and personnel resources. The effect of these competitive factors cannot be predicted.

Price, contract terms, availability of rigs and related equipment and quality of service, including pipeline connection times and distribution efficiencies affect competition. We believe that our extensive acreage position and our access to gathering and pipeline infrastructure in Pennsylvania, along with our expected activity level and the related services and equipment that we have secured for the upcoming years, enhance our competitive position over other producers who do not have similar systems or services in place.

Major Customers

During the years ended December 31, 2016, 2015 and 2014, two customers accounted for approximately 19% and 10%, two customers accounted for approximately 16% and 14% and two customers accounted for approximately 14% and 10%, respectively, of our total sales. We do not believe that the loss of any of these customers would have a material adverse effect on us because alternative customers are readily available.

Seasonality

Demand for natural gas has historically been seasonal, with peak demand and typically higher prices occurring during the colder winter months.

Regulation of Oil and Natural Gas Exploration and Production

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. This regulation includes requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled in a given field and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. We do not believe, however, we are affected differently by these regulations than others in the industry.

Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of the natural gas we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938 (NGA), the Natural

Gas Policy Act of 1978 (NGPA), and the regulations promulgated under those statutes, the FERC regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or

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gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Effective beginning in January 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all “first sales” of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC granted to all producers such as us a “blanket certificate of public convenience and necessity” authorizing the sale of natural gas for resale without further FERC approvals. As a result of this policy, all of our produced natural gas is sold at market prices, subject to the terms of any private contracts that may be in effect. In addition, under the provisions of the Energy Policy Act of 2005 (2005 Act), the NGA was amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established regulations intended to increase natural gas pricing transparency by, among other things, requiring market participants to report their gas sales transactions annually to the FERC. The 2005 Act also significantly increased the penalties for violations of the NGA and the FERC’s regulations up to $1,000,000 per day per violation. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties and procedure under its enforcement program.

Some of our pipelines are subject to regulation by the FERC. We own an intrastate natural gas pipeline through our wholly owned subsidiary, Cranberry Pipeline Corporation, that provides interstate transportation and storage services pursuant to Section 311 of the NGPA, as well as intrastate transportation and storage services that are regulated by the West Virginia Public Service Commission. For qualified intrastate pipelines, FERC allows interstate transportation service “on behalf of” interstate pipelines or local distribution companies served by interstate pipelines without subjecting the intrastate pipeline to the more comprehensive NGA jurisdiction of the FERC. We provide Section 311 service in accordance with a publicly available Statement of Operating Conditions filed with FERC under rates that are subject to approval by the FERC. On December 18, 2012, we filed with the FERC a petition for rate approval of our existing interstate transportation rates and a proposed decrease of our storage rates. By Letter Order issued May 15, 2013, the FERC approved the rate petition.

In 2012 we executed a precedent agreement with Constitution, at the time a wholly owned subsidiary of Williams Partners L.P., for 500,000 Dth per day of pipeline capacity and acquired a 25% equity interest in a pipeline to be constructed in the states of New York and Pennsylvania. On June 12, 2013, the project sponsors filed an application with FERC requesting a certificate of public convenience and necessity to construct and operate the 124 mile pipeline project that, once completed, will provide 650,000 Dth per day of pipeline capacity. On December 2, 2014, the FERC issued a certificate of public convenience and necessity, authorizing the construction and operation of the pipeline project. While FERC has issued the certificate, the project scope or timeline for construction and eventual in-service date has been impacted by the public regulatory permitting process. Currently, the in-service date for Constitution is expected in the second half of 2018. When placed into service, the project pipeline will be an interstate pipeline subject to full regulation by FERC under the NGA.

Additionally, in 2014 we executed a precedent agreement with Transcontinental Gas Pipe Line Company, LLC (Transco) for 850,000 Dth per day of pipeline capacity and acquired a 20% equity interest in Meade, which was formed to construct a pipeline with Transco from Susquehanna County, Pennsylvania to an interconnect with Transco's mainline in Lancaster County, Pennsylvania. The proposed pipeline will be an interstate pipeline subject to full regulation by the FERC under the NGA. Transco filed an application for a certificate of public convenience and necessity with the FERC on March 31, 2015. On February 3, 2017, the FERC issued a certificate of public convenience and necessity, authorizing the construction and operation of the pipeline project.

Our production and gathering facilities are not subject to jurisdiction of the FERC; however, our natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation because the cost of transporting the natural gas once sold to the consuming market is a factor in the prices we receive. Beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted a series of rulemakings that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, requiring interstate pipeline companies to separate their wholesale gas marketing business from their gas transportation business, and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their natural gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants. Most pipelines have also implemented the large scale divestiture of their natural gas gathering facilities to affiliated or non affiliated companies. Interstate pipelines are required to provide unbundled, open and nondiscriminatory transportation and transportation related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. As a result of FERC requiring natural gas pipeline companies to separate marketing and

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transportation services, sellers and buyers of natural gas have gained direct access to pipeline transportation services, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, we cannot predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Further, we cannot predict whether the recent trend toward federal deregulation of the natural gas industry will continue or what effect future policies will have on our sale of gas.

Federal Regulation of Swap Transactions

We use derivative financial instruments such as collar, swap and basis swap agreements to attempt to more effectively manage price risk due to the impact of changes in commodity prices on our operating results and cash flows. Following enactment of the Dodd Frank Wall Street Reform and Consumer Protection Act (Dodd Frank Act) in July 2010, the Commodity Futures Trading Commission (CFTC) has promulgated regulations to implement statutory requirements for swap transactions, including certain options. The CFTC regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. In addition, all swap market participants are subject to new reporting and recordkeeping requirements related to their swap transactions. We believe that our use of swaps to hedge against commodity exposure qualifies us as an end user, exempting us from the requirement to centrally clear our swaps. Nevertheless, changes to the swap market as a result of Dodd Frank implementation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Federal Regulation of Petroleum

Our sales of crude oil and NGLs are not regulated and are made at market prices. However, the price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines, which are regulated by the FERC under the Interstate Commerce Act (ICA). FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service and that such service not be unduly discriminatory or preferential.

Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may increase or decrease the cost of transporting crude oil and NGLs by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In December 2015, to implement this required five year re determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 1.23% should be the oil pricing index for the five year period beginning July 1, 2016. The result of indexing is a “ceiling rate” for each rate, which is the maximum at which the pipeline may set its interstate transportation rates. A pipeline may also file cost of service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Rates are subject to challenge by protest when they are filed or changed. For indexed rates, complaints alleging that the rates are unjust and unreasonable may only be pursued if the complainant can show that a substantial change has occurred since the enactment of Energy Policy Act of 1992 in either the economic circumstances of the pipeline or in the nature of the services provided, that were a basis for the rate. There is no such limitation on complaints alleging that the pipeline’s rates or terms and conditions of service are unduly discriminatory or preferential. We are unable to predict with certainty the effect upon us of these periodic reviews by the FERC of the pipeline index.

Pipeline Safety Regulation

Certain of our pipeline systems and storage fields in West Virginia are regulated for safety compliance by the U.S. Department of Transportation (DOT) and the West Virginia Public Service Commission. In 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (2002 Act), which contains a number of provisions intended to increase pipeline operating safety. The DOT's final regulations implementing the act became effective February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission and non rural gathering pipeline facilities in certain locations within ten years, and at least every seven years thereafter. On March 15, 2006, the DOT revised these regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the

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current regulations applicable to safety and inspection of gathering lines in non rural areas, and adopt new compliance deadlines. The initial baseline assessments under our integrity management program for our pipeline system in West Virginia were completed in January 2013. Pipeline integrity was confirmed at each of the targeted assessment sites. A new seven year reassessment cycle began during 2013.

In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act), which reauthorized the programs adopted under the 2002 Act, proposed enhancements for state programs to reduce excavation damage to pipelines, established increased federal enforcement of one call excavation programs, and established a new program for review of pipeline security plans and critical facility inspections. Pursuant to the PIPES Act, the DOT issued regulations on May 5, 2011 that would, with limited exceptions, subject all low stress hazardous liquids pipelines, regardless of location or size, to the DOT's pipeline safety regulations.

In December 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The act increased the maximum civil penalties for pipeline safety administrative enforcement actions; required the DOT to issue regulations requiring the use of automatic or remote controlled shutoff valves on new and rebuilt pipelines and to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure safety, and the use of leak detection systems by hazardous liquid pipelines; required pipeline operators to verify their records on maximum allowable operating pressure; and imposed new emergency response and incident notification requirements. The act reflects many of the areas of possible regulatory change described in an Advance Notice of Proposed Rulemaking issued by the DOT on August 18, 2011, including revisions to DOT's civil penalty authority and the requirement that pipelines verify maximum allowable operating pressure.

On December 3, 2009, the DOT adopted a regulation requiring gas and hazardous liquid pipelines that use supervisory control and data acquisition (SCADA) systems and have at least one controller and control room to develop written control room management procedures by August 1, 2011 and implement the procedures by February 1, 2013. The DOT expedited the program implementation deadline to October 1, 2011 for most of the requirements, except for certain provisions regarding adequate information and alarm management, which had a program implementation deadline of August 1, 2012. We developed and implemented the required control room management procedures in accordance with the deadlines. Effective January 1, 2011, natural gas and hazardous liquid pipelines also became subject to updated reporting requirements with DOT.

The cost of compliance with DOT's integrity management rules depends on integrity testing and the repairs found to be necessary by such testing. Changes to the amount of pipe subject to integrity management, whether by expansion of the definition of the type of areas subject to integrity management procedures or of the applicability of such procedures outside of those defined areas can have a significant impact on costs we may incur to ensure compliance.

On April 8, 2016, the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) published a Notice of Proposed Rulemaking that would amend existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. PHMSA issued, but has yet to publish, a similar rule for hazardous liquids pipelines on January 13, 2017. That rule extends regulatory reporting requirements to all liquid gathering lines, requires additional event-driven and periodic inspections, requires use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria, and requires certain pipelines to eventually accommodate inline inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review.

In the future other laws and regulations may be enacted or adopted or existing laws may be reinterpreted in a manner that could impact our compliance costs. In addition, we may be subject to DOT's enforcement actions and penalties for failure to comply with pipeline regulations.

Environmental and Safety Regulations

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Governmental authorities enforce compliance with their regulations through fines, injunctions or both.

Government regulations can increase the cost of planning, designing, installing and operating, and can affect the timing of installing and operating, oil and natural gas facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of oil and natural gas production operations. No assurance can be given that significant costs and liabilities will not be incurred. Also, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and natural gas production could result in substantial costs and liabilities to us.

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U.S. laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment or otherwise relating to the protection of the environment.

Solid and Hazardous Waste. We currently own or lease, and have in the past owned or leased, numerous properties that were used for the production of oil and natural gas for many years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other wastes may have been disposed of or released on or under the properties currently owned or leased by us. State and federal laws applicable to oil and gas wastes and properties have become stricter over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators) or clean up property contamination (including groundwater contamination by prior owners or operators) or to perform plugging operations to prevent future contamination.

We generate some hazardous wastes that are already subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (EPA) has limited the disposal options for certain hazardous wastes. It is possible that certain wastes currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess 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 by March 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. We could, therefore, be subject to more rigorous and costly disposal requirements in the future than we encounter today.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the "Superfund" law, and comparable state laws and regulations impose liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the current and past owners and operators of a site where the release occurred and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA, and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In addition, 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. In the course of business, we have used materials and generated wastes and will continue to use materials and generate wastes that may fall within CERCLA's definition of hazardous substances. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such substances have been released.

Oil Pollution Act. The Federal Oil Pollution Act of 1990 (OPA) and resulting regulations impose a variety of obligations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. The term "waters of the United States" has been broadly defined to include inland water bodies, including wetlands and intermittent streams. The OPA assigns joint and several strict liability to each responsible party for oil removal costs and a variety of public and private damages. The OPA also imposes ongoing requirements on operators, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe that we substantially comply with the Oil Pollution Act and related federal regulations.

Endangered Species Act. The Endangered Species Act (ESA) restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA, nor are we aware of any proposed listings that will affect our operations. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Clean Water Act. The Federal Water Pollution Control Act (Clean Water Act) and resulting regulations, which are primarily implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities or to cease hauling wastewaters to facilities owned by others that are the source of water discharges. We believe that we substantially comply with the Clean Water Act and related federal and state regulations.

Clean Air Act. Our operations are subject to the Federal Clean Air Act and comparable local and state laws and regulations to control emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control toxic air pollutants and greenhouse gases might require installation of additional controls. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure to comply strictly with air regulations or permits. Regulatory agencies could also require us to cease construction or operation of certain facilities or to install additional controls on certain facilities that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Some of our producing wells and associated facilities are subject to restrictive air emission limitations and permitting requirements. In 2012, the EPA published final New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) that amended the existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and natural gas production, transmission and distribution facilities. In June 2016, the EPA published a final rule that updates and expands the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In addition, the EPA has announced that it intends to impose methane emission standards for existing sources and has issued information collection requests for oil and natural gas facilities. The EPA also published a final rule in June 2016 concerning aggregation of sources that affects source determinations for air permitting in the oil and gas industry. If we are unable to comply with air pollution regulations or to obtain permits for emissions associated with our operations, we could be required to forego construction, modification or certain operations. These regulations may also increase compliance costs for some facilities we own or operate, and result in administrative, civil and/or criminal penalties for non-compliance. Obtaining permits may delay the development of our oil and natural gas projects, including the construction and operation of facilities.

Safe Drinking Water Act. The Safe Drinking Water Act (SDWA) and comparable local and state provisions restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state’s environmental authority. These regulations may increase the costs of compliance for some facilities.

Hydraulic Fracturing. Many of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and natural gas wells. This technology involves the injection of fluids, usually consisting mostly of water but typically including small amounts of several chemical additives, as well as sand into a well under high pressure in order to create fractures in the formation that allow oil or natural gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal, state and local levels have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and natural gas production activities using hydraulic fracturing techniques which could have an adverse effect on oil and natural gas production activities, including operational delays or increased operating costs in the production of oil and natural gas from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of 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 natural gas wells and increased compliance costs, which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells. For additional information about hydraulic fracturing and related environmental matters, please read “Risk Factors-Federal and state legislation and regulatory initiatives related to oil and gas development, including hydraulic fracturing, could result in increased costs and operating restrictions or delays” in Item 1A.

Greenhouse Gas. In response to studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to global climate change, the United States Congress has considered, but not enacted, legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and 2050. In addition, many states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA has also begun to regulate carbon dioxide and other greenhouse gas emissions under existing provisions of the Clean Air Act. This includes proposed regulation of methane emissions from the oil and gas sector. If we are unable to recover or pass through a significant portion of our costs related to complying with current and future regulations relating to climate change and GHGs, it could materially affect our operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Future legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy.

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Please read “Risk Factors-Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and natural gas that we produce” in Item 1A.

OSHA and Other Laws and Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA), and comparable state laws. The OSHA hazard communication standard, the EPA community right to know regulations under the Title III of CERCLA and similar state laws require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards related to workplace exposure to hazardous substances and employee health and safety.

Employees

As of December 31, 2016, we had 421 employees. In addition, we had 155 employees that are employed by our wholly-owned subsidiary, GasSearch Drilling Services Corporation. We recognize that our success is significantly influenced by the relationship we maintain with our employees. Overall, we believe that our relations with our employees are satisfactory. Our employees are not represented by a collective bargaining agreement.

Website Access to Company Reports

We make available free of charge through our website, www.cabotog.com, our annual reports on Form 10 K, quarterly reports on Form 10 Q, current reports on Form 8 K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by us. The public may read and copy materials that we file with the SEC at the SEC’s Public Reference Room located at 100 F Street, NE, Washington, DC 20549. Information regarding the operation of the Public Reference Room can be obtained by calling the SEC at 1 800 SEC 0330.

Corporate Governance Matters

Our Corporate Governance Guidelines, Corporate Bylaws, Audit Committee Charter, Compensation Committee Charter, Corporate Governance and Nominations Committee Charter, Code of Business Conduct and Safety and Environmental Affairs Committee Charter are available on our website at www.cabotog.com, under the “Governance” section of “About Cabot.” Requests can also be made in writing to Investor Relations at our corporate headquarters at Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas 77024.

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ITEM 1A. RISK FACTORS

Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prices we receive for the natural gas and oil that we sell. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Because our reserves are predominantly natural gas (approximately 97% of equivalent proved reserves), changes in natural gas prices have a more significant impact on our financial results than oil prices. Natural gas prices, based on the twelve-month average of the first of the month Henry Hub index price, were $2.48 per Mmbtu in 2016 compared to $2.59 per Mmbtu in 2015. Oil prices, based on the NYMEX monthly average price, were $42.75 per barrel in 2016 compared to $50.28 per barrel in 2015, and have yet to recover to levels experienced in 2014 despite recent price improvements. Low prices throughout 2015 and 2016 have had, and any substantial or extended decline in future natural gas or crude oil prices would have, a material adverse effect our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments. Furthermore, substantial, extended decreases in natural gas and crude oil prices may cause us to delay or postpone a significant portion of our exploration, development and exploitation projects or may render such projects uneconomic, which may result in significant downward adjustments to our estimated proved reserves and could negatively impact our ability to borrow and cost of capital and our ability to access capital markets, increase our costs under our revolving credit facility, and limit our ability to execute aspects of our business plans. See "Risk Factors-Future natural gas and oil price declines may result in additional write-downs of the carrying amount of our oil and gas properties, which could materially and adversely affect our results of operations."

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include but are not limited to the following:

- the levels and location of natural gas and oil supply and demand and expectations regarding supply and demand, including the potential long-term impact of an abundance of natural gas from shale (such as that produced from our Marcellus Shale properties) on the global natural gas supply;
- the level of consumer demand for natural gas and oil;
- weather conditions;
- political conditions or hostilities in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability and willingness of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level and quantities of foreign imports;
- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall economic conditions, including the value of the U.S. dollar relative to other major currencies.

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These factors and the volatile nature of the energy markets make it impossible to predict the future prices of natural gas and oil. If natural gas and oil prices remain low or continue to decline significantly for a sustained period of time, the lower prices may cause us to reduce our planned drilling program or adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including:

- decreases in natural gas and oil prices;
- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- surface access restrictions;
- loss of title or other title related issues;
- lack of available gathering or processing facilities or delays in the construction thereof;
- compliance with, or changes in, governmental requirements and regulation, including with respect to wastewater disposal, discharge of greenhouse gases and fracturing; and
- costs of shortages or delays in the availability of drilling rigs or crews and the delivery of equipment and materials.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate within a particular geographic area may decline. We may be unable to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may be unable to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects and any delays in obtaining such permits.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

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

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data.

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

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average index price for the respective commodity, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. The present value of future cash flows are based on $1.74 per Mcf of natural gas, $10.69 per Bbl of NGLs and $37.54 per Bbl of oil as of December 31, 2016. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Future natural gas and oil price declines may result in additional write-downs of the carrying amount of our oil and gas properties, which could materially and adversely affect our results of operations.

The value of our oil and gas properties depends on prices of natural gas and oil. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make material downward adjustments to our estimated proved reserves, and could result in an impairment charge and a corresponding write-down of the carrying amount of our oil and natural gas properties. For example, in December 2015, we recorded an impairment of approximately $114.9 million associated with oil and gas properties in certain non-core fields in south Texas, east Texas and Louisiana. The impairment of these fields was due to a significant decline in commodity prices in late 2015. Because our reserves are predominately natural gas (approximately 97% of equivalent proved reserves), changes in natural gas prices have a more significant impact on our financial results than oil prices.

We evaluate our oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate a property's carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future natural gas and oil prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. In the event that commodity prices decline, there could be a significant revision in the future.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop and produce economically.

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Our reserve report estimates that production from our proved developed reserves as of December 31, 2016 will decrease at a rate of 7%, 27%, 19% and 15% during 2017, 2018, 2019 and 2020, respectively. Future development of proved undeveloped and other reserves currently not classified as proved developed producing will impact these rates of decline. Because of higher initial decline rates from newly developed reserves, we consider this pattern fairly typical.

Exploration, development and exploitation activities involve numerous risks that may result in, among other things, dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all.

We rely upon access to both our revolving credit facility and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by cash flow from operations or other sources. Future challenges in the global financial system, including the capital markets, may adversely affect our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. Adverse economic and market conditions could adversely affect the collectability of our trade receivables and cause our commodity hedging counterparties to be unable to perform their obligations or to seek bankruptcy protection. Future challenges in the economy could also lead to reduced demand for natural gas which could have a negative impact on our revenues.

Risks associated with our debt and the provisions of our debt agreements could adversely affect our business, financial position and results of operations.

As of December 31, 2016, we had approximately $1.5 billion of debt outstanding and we may incur additional indebtedness in the future. Increases in our level of indebtedness may:

- require us to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;
- limit our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making certain investments, and paying dividends;
- place us at a competitive disadvantage compared to our competitors with lower debt service obligations;
- depending on the levels of our outstanding debt, limit our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes; and
- increase our vulnerability to downturns in our business or the economy, including declines in prices for natural gas and oil.

In addition, the interest rates that we pay on our senior unsecured notes and the margins we pay under our revolving credit facility depend on our leverage ratio and our asset coverage ratio. Accordingly, increases in the amount of our indebtedness without corresponding increases in our earnings or the present value of our reserves, or decreases in our earnings or the present value of our natural gas and oil reserves without a corresponding decrease in our indebtedness, will result in an increase in our interest expense.

Our debt agreements also require compliance with covenants to maintain specified financial ratios. If the price that we receive for our natural gas and oil production deteriorates from current levels or continues for an extended period, it could lead to reduced revenues, cash flow and earnings, which in turn could lead to a default under the ratios described above. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period. A prolonged period of decreased natural gas and oil prices could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. In order to provide a margin of comfort with regard to these financial covenants, we may seek to reduce our capital expenditures, sell non-strategic assets or opportunistically modify or increase our derivative instruments to the extent permitted under our debt agreements. In addition, we may seek to refinance or restructure all or a portion of our indebtedness. We cannot assure you that we will be able to successfully execute any of these strategies, and such strategies may be unavailable on favorable terms or at all. For more information about our debt agreements, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Financial Condition - Capital Resources and Liquidity."

The borrowing base under our revolving credit facility may be reduced, which could limit us in the future.
The borrowing base under our revolving credit facility is currently $3.2 billion, and lender commitments under our revolving credit facility are $1.8 billion. The borrowing base is redetermined annually under the terms of the revolving credit facility on April 1. In addition, either we or the banks may request an interim redetermination twice a year or in conjunction with certain

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acquisitions or sales of oil and gas properties. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations, including any such debt repayment obligations.

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

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2017 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2017 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

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

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

Our ability to sell our natural gas and oil production and/or the prices we receive for our production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. We deliver our natural gas and oil production primarily 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. Third-party systems and facilities may be unavailable due to market conditions or mechanical or other reasons. In addition, at current commodity prices, construction of new pipelines and building of such infrastructure may be slower to build out. To the extent these services are unavailable, we would be unable to realize revenue from wells served by such facilities until suitable arrangements are made to market our production. Our failure to obtain these services on acceptable terms could materially harm our business.

For example, the Marcellus Shale wells we have drilled to date have generally reported very high initial production rates. The amount of natural gas being produced in the area from these new wells, as well as natural gas produced from other existing wells, may exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available. In such event, this could result in wells being shut in or awaiting a pipeline connection or capacity and/or natural gas being sold at much lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations and cash flows.

We are subject to complex laws and regulations, including environmental and safety regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including drilling, permitting and safety laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations,

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and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities, and new laws and regulations or revisions or reinterpretations of existing laws and regulations could further increase these costs. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. For example, we could be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. Failure to comply with these 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. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Acquired properties may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include estimates of recoverable reserves, exploration potential, future natural gas and oil prices, operating costs, production taxes and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise.

There may be threatened or contemplated claims against the assets or businesses we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We often assume certain liabilities, and we may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. At times, we acquire interests in properties on an "as is" basis with limited representations and warranties and limited remedies for breaches of such representations and warranties. In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties.

The integration of the properties we acquire could be difficult, and may divert management's attention away from our existing operations.

The integration of the properties we acquire could be difficult, and may divert management's attention and financial resources away from our existing operations. These difficulties include:

- the challenge of integrating the acquired properties while carrying on the ongoing operations of our business;
- the inability to retain key employees of the acquired business;
- potential lack of operating experience in a geographic market of the acquired properties; and
- the possibility of faulty assumptions underlying our expectations.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our existing business. If management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- well site blowouts, cratering and explosions;
- equipment failures;
- pipe or cement failures and casing collapses, which can release natural gas, oil, drilling fluids or hydraulic fracturing fluids;
- uncontrolled flows of natural gas, oil or well fluids;

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- pipeline ruptures;
- fires;
- formations with abnormal pressures;
- handling and disposal of materials, including drilling fluids and hydraulic fracturing fluids;
- release of toxic gas;
- buildup of naturally occurring radioactive materials;
- pollution and other environmental risks, including conditions caused by previous owners or lessors of our properties; and
- natural disasters.

Any of these events could result in injury or loss of human life, loss of hydrocarbons, significant damage to or destruction of property, environmental pollution, regulatory investigations and penalties, suspension or impairment of our operations and substantial losses to us.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase these risks. As of December 31, 2016, we owned or operated approximately 3,100 miles of natural gas gathering and pipeline systems. As part of our normal maintenance program, we have identified certain segments of our pipelines that we believe periodically require repair, replacement or additional maintenance.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance against some, but not all, operating risks and losses. We do not carry business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. As of December 31, 2016, non-operated wells represented approximately 6.5% of our total owned gross wells, or approximately 1.9% of our owned net wells. We have limited ability to influence or control the operation or future development of these non-operated properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the capital, equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe will be increasingly important to attaining success in the industry. These companies may also have a greater ability to continue drilling activities during periods of low natural gas and oil prices and to absorb the burden of current and future governmental regulations and taxation.

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We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use financial derivative instruments to manage price risk associated with our natural gas and crude oil production. While there are many different types of derivatives available, we generally utilize collar, swap and basis swap agreements to manage price risk more effectively.

The collar arrangements are put and call options used to establish floor and ceiling prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The swap agreements call for payments to, or receipts from, counterparties based on whether the index price for the period is greater or less than the fixed price established for that period when the swap is put in place. These arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production;
- production is less than expected; or
- a counterparty is unable to satisfy its obligations.

The CFTC has promulgated regulations to implement statutory requirements for swap transactions. These regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. While we believe that our use of swap transactions exempt us from certain regulatory requirements, the changes to the swap market due to increased regulation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

We will continue to evaluate the benefit of utilizing derivatives in the future. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A for further discussion concerning our use of derivatives.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Federal and state legislation and regulatory initiatives related to oil and gas development, including hydraulic fracturing, could result in increased costs and operating restrictions or delays.

Most of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of several chemical additives—as well as sand or other proppants into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well.

Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has released permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where EPA is the permitting authority, including Pennsylvania. As a result, we may be subject to additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. In addition, from time to time, legislation has been introduced, but not enacted, in Congress that would provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids. If enacted, this legislation could establish an additional level of regulation and permitting at the federal, state or local levels, and could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely

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affect the environment, including groundwater, soil or surface water. Moreover, in May 2014, the EPA announced an Advanced Notice of Proposed Rulemaking under the Toxic Substances Control Act relating to data collection, including the chemical substances and mixtures used in hydraulic fracturing. Further, in March 2015, the Department of the Interior's Bureau of Land Management (BLM) issued a final rule to regulate hydraulic fracturing on public and Indian land; however, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. This decision is currently being appealed by the federal government. We voluntarily disclose on a well-by-well basis the chemicals we use in the hydraulic fracturing process at www.fracfocus.org.

In addition, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal, which could have an adverse effect on oil and natural gas production activities, including operational delays or increased operating costs in the production of oil and natural gas from developing shale plays, or could make it more difficult to perform hydraulic fracturing.

On August 16, 2012, the EPA published final rules that establish new air emission control requirements for natural gas and NGL production, processing and transportation activities, including NSPS to address emissions of sulfur dioxide and volatile organic compounds, and NESHAPS to address hazardous air pollutants frequently associated with gas production and processing activities. In June 2016, the EPA published a final rule that updates and expands the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In addition, the EPA has announced that it intends to impose methane emission standards for existing sources and has issued information collection requests for oil and natural gas facilities. The EPA also published a final rule in June 2016 concerning aggregation of sources that affects source determinations for air permitting in the oil and gas industry.

Compliance with these requirements, especially the new methane regulation, may require modifications to certain of our operations, including the installation of new equipment to control emissions at the well site that could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. Similarly, aggregating our oil and gas facilities for permitting could result in more complex, costly, and time consuming air permitting. Particularly in regard to obtaining pre-construction permits, the final aggregation rule could add costs and cause delays in our operations.

In addition to these federal legislative and regulatory proposals, some states in which we operate, such as Pennsylvania, West Virginia and Texas, and certain local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, including requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. For example, the City of Denton, Texas adopted a moratorium on hydraulic fracturing in November 2014, though it was later lifted in 2015, and New York issued a statewide ban on hydraulic fracturing in June 2015. In addition, Pennsylvania's Act 13 of 2012 became law on February 14, 2012 and amended the state's Oil and Gas Act to, among other things, increase civil penalties and strengthen the Pennsylvania Department of Environmental Protection's (PaDEP) authority over the issuance of drilling permits. Although the Pennsylvania Supreme Court struck down portions of Act 13 that made statewide rules on oil and gas preempt local zoning rules, this could lead to additional local restrictions on oil and gas activity in the state. The Pennsylvania Supreme Court heard additional challenges to Act 13 and struck several more provisions in September 2016, including the provision requiring notification of spills and leaks only to public water suppliers.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our operations, could adversely impact our operations. Moreover, 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 wastes associated with the exploration, development or production of natural gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition. For example, in April 2011, PaDEP called on all Marcellus Shale natural gas drilling operators to voluntarily cease by May 19, 2011 delivering wastewater to those centralized treatment facilities that were grandfathered from the application of PaDEP's Total Dissolved Solids regulations. In June 2016, the EPA published final pretreatment standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works (POTWs). The regulations were developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. In response to these actions, operators including us have begun to rely more on recycling of flowback and produced water from well sites as a preferred alternative to disposal.

A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing practices. For example, the EPA conducted a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released its final report in December 2016. It concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. This study and other studies that may be undertaken by EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and natural gas that we produce.

Climate change, the costs that may be associated with its effects, and the regulation of greenhouse gas (GHG) emissions have the potential to affect our business in many ways, including increasing the costs to provide our products and services, reducing the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks. In addition, legislative and regulatory responses related to GHG emissions and climate change may increase our operating costs. The United States Congress has previously considered legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in GHG emissions. The United States was actively involved in the negotiations at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their nationally determined contributions, which set emissions reduction goals, every five years. The United States signed the Paris Agreement in April 2016. Increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

In September 2009, the EPA finalized a mandatory GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions beginning January 1, 2010. The rule applies to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent (CO_2e) emissions per year and to most upstream suppliers of fossil fuels, as well as manufacturers of vehicles and engines. Subsequently, in November 2010, the EPA issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of CO_2e per year. The rule required reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA each year in March under this rule and have submitted our annual reports in compliance with the deadline. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA. However, in June 2014, the U.S. Supreme Court, in UARG v. EPA, limited the application of the GHG permitting requirements under the Prevention of Significant Deterioration and Title V permitting programs to sources that would otherwise need permits based on the emission of conventional pollutants. In October 2015, the EPA finalized rules that added new sources to the scope of the GHG monitoring and reporting requirements. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. Also, in November 2016, the EPA published a final rule adding monitoring methods for detecting leaks from oil and gas equipment and emission factors for leaking equipment to be used to calculate and report GHG emissions resulting from equipment leaks.

Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the passage of any federal or state climate change laws or regulations in the future could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

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Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. In addition, warmer winters as a result of global warming could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Acts of terrorism, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Cyber-attacks targeting our systems or the oil and gas industry systems and infrastructure could adversely affect our business.

Our business and the oil and gas industry in general have become increasingly dependent on digital data, computer networks and connected infrastructure. We depend on this technology to record and store financial data, estimate quantities of natural gas and crude oil reserves, analyze and share operating data and communicate internally and externally. Computers control nearly all of the oil and gas distribution systems in the United States, which are necessary to transport our products to market.

A cyber-attack may involve a hacker, a virus, malware, phishing or other actions for the purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. Unauthorized access to our proprietary information could lead to data corruption or communication or operational disruptions. A cyber-attack directed at oil and gas distribution systems could damage those assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for transported products.

We can provide no assurance that we will not suffer such attacks in the future. As cyber-attackers become more sophisticated, we may be required to expend significant additional resources to continue to protect our business or remediate the damage from cyber-attacks.

Certain federal income tax law changes have been proposed that, if passed, would have an adverse effect on our financial position, results of operations, and cash flows.

Substantive changes to existing federal income tax laws have been proposed that, if adopted, would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and would impose new taxes. The proposals include: repeal of the percentage depletion allowance for oil and natural gas properties; elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these proposals become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities in the U.S. Since none of these proposals have yet to become law, we do not know the ultimate impact these proposed changes may have on our business.

Provisions of Delaware law and our bylaws and charter could discourage change in control transactions and prevent stockholders from receiving a premium on their investment.

Our charter authorizes our Board of Directors to set the terms of preferred stock. In addition, Delaware law contains provisions that impose restrictions on business combinations with interested parties. Our bylaws prohibit the calling of a special meeting by our stockholders and place procedural requirements and limitations on stockholder proposals at meetings of stockholders. Because of these provisions of our charter, bylaws and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our Board of

Directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our stockholders to benefit from transactions that are opposed by an incumbent Board of Directors.

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The personal liability of our directors for monetary damages for breach of their fiduciary duty of care is limited by the Delaware General Corporation Law and by our charter.

The Delaware General Corporation Law allows corporations to limit available relief for the breach of directors' duty of care to equitable remedies such as injunction or rescission. Our charter limits the liability of our directors to the fullest extent permitted by Delaware law. Specifically, our directors will not be personally liable for monetary damages for any breach of their fiduciary duty as a director, except for liability:

- for any breach of their duty of loyalty to the company or our stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- under provisions relating to unlawful payments of dividends or unlawful stock repurchases or redemptions; and
- for any transaction from which the director derived an improper personal benefit.

This limitation may have the effect of reducing the likelihood of derivative litigation against directors, and may discourage or deter stockholders or management from bringing a lawsuit against directors for breach of their duty of care, even though such an action, if successful, might otherwise have benefited our stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Legal Matters

The information set forth under the heading "Legal Matters" in Note 9 of the Notes to Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

Environmental Matters

On November 12, 2015, we received a proposed Consent Order and Agreement from the Pennsylvania Department of Environmental Protection (PaDEP) relating to gas migration allegations in an area surrounding several wells owned and operated by us in Susquehanna County, Pennsylvania. The allegations relating to these wells were initially raised by residents in the area in August 2011. We received a Notice of Violation from the PaDEP in September 2011 for failure to prevent the migration of gas into fresh groundwater sources in the area surrounding these wells. Since then, we have been engaged with the PaDEP in investigating the incident and have performed appropriate remediation efforts, including the provision of alternative sources of drinking water to affected residents. We believe the source of methane has been remediated and we entered into a Consent Order and Agreement with the PaDEP on December 30, 2016. We agreed to pay a civil monetary penalty in the amount of approximately $0.3 million and to continue to provide alternative sources of drinking water to affected residents until the affected water supplies are permanently restored. Further, the related gas well is being permanently plugged. Following the plugging of the gas well, additional monitoring will be required to ensure the source of methane has been remediated. Cabot continues to work with the PaDEP to bring this matter to a close.

From time to time we receive notices of violation from governmental and regulatory authorities in areas in which we operate relating to alleged violations of environmental statutes or the rules and regulations promulgated thereunder. While we cannot predict with certainty whether these notices of violation will result in fines and/or penalties, if fines and/or penalties are imposed, they may result in monetary sanctions, individually or in the aggregate, in excess of $100,000.

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ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 22, 2017 about our executive officers, as such term is defined in Rule 3b-7 of the Securities Exchange Act of 1934, and certain of our other officers.

Name	Age	Position	Officer Since
Dan O. Dinges	63	Chairman, President and Chief Executive Officer	2001
Scott C. Schroeder	54	Executive Vice President and Chief Financial Officer	1997
Jeffrey W. Hutton	61	Senior Vice President, Marketing	1995
Todd L. Liebl	59	Senior Vice President, Land and Business Development	2012
Steven W. Lindeman	56	Senior Vice President, South Region and Engineering	2011
Phillip L. Stalnaker	57	Senior Vice President, North Region	2009
G. Kevin Cunningham	63	Vice President and General Counsel	2010
Matthew P. Kerin	36	Vice President and Treasurer	2014
Todd M. Roemer	46	Vice President and Controller	2010
Deidre L. Shearer	49	Vice President and Corporate Secretary	2012

All officers are elected annually by our Board of Directors. All of the executive officers have been employed by Cabot Oil & Gas Corporation for at least the last five years, except for Mr. Matthew P. Kerin.

Mr. Kerin joined the Company in March 2012 and was appointed Treasurer in September 2014 and was promoted to Vice President in February 2017. Mr. Kerin most recently served as Manager - Finance and Investor Relations. Prior to joining the Company, Mr. Kerin served as an Associate in the Oil and Gas Investment Banking group at J.P. Morgan Securities. He is a graduate of Texas A&M University with a Bachelor in Business Administration degree in Accounting and a Master of Science degree in Finance. He is also a graduate from the Jones Graduate School of Business at Rice University with a Master in Business Administration degree with a concentration in Finance and Energy.

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PART II

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

Our common stock is listed and principally traded on the New York Stock Exchange under the ticker symbol "COG." The following table presents the high and low closing sales prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system. Cash dividends paid per share of the common stock are also shown.

	High	Low	Dividends
2016			
First Quarter	$22.88	$15.42	$ 0.02
Second Quarter	$25.94	$22.23	$ 0.02
Third Quarter	$26.47	$23.52	$ 0.02
Fourth Quarter	$25.69	$20.03	$ 0.02
2015			
First Quarter	$30.01	$26.44	$ 0.02
Second Quarter	$35.34	$29.95	$ 0.02
Third Quarter	$30.98	$21.28	$ 0.02
Fourth Quarter	$23.70	$15.03	$ 0.02

As of February 1, 2017, there were 383 registered holders of our common stock.

EQUITY COMPENSATION PLAN INFORMATION

The following table provides information as of December 31, 2016 regarding the number of shares of common stock that may be issued under our 2014 and 2004 incentive plans. Effective May 1, 2014, no additional awards are to be granted under the 2004 Incentive Plan.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	3,190,351 (1)	$ 13.04 (2)	15,995,342 (3)
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	3,190,351	$ 13.04	15,995,342

(1) Includes 483,286 SARs to be settled in common stock, which are fully vested; 993,530 employee performance shares, the performance periods of which end on December 31, 2016, 2017 and 2018; 885,213 TSR performance shares, the performance periods of which end on December 31, 2016, 2017 and 2018; 479,784 hybrid performance shares, which vest, if at all, in 2017, 2018, and 2019; and 348,538 restricted stock units awarded to the non-employee directors, the restrictions on which lapse upon a non-employee director's departure from the Board of Directors.

(2) Price is only with respect to the 483,286 SARs outstanding because all other outstanding awards are issued without an exercise price.

(3) Includes 43,175 shares of restricted stock, the restrictions on which lapse on various dates in 2017, 2018 and 2019; and 15,952,167 shares that are available for future grants under the 2014 Incentive Plan.

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ISSUER PURCHASES OF EQUITY SECURITIES

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During 2016, we did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of remaining shares that may be purchased under the plan as of December 31, 2016 was 10,107,320.

PERFORMANCE GRAPH

The following graph compares our common stock performance ("COG") with the performance of the Standard & Poor's 500 Stock Index and the Dow Jones U.S. Exploration & Production Index for the period December 2011 through December 2016. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2011 and that all dividends were reinvested.

	December 31,					
Calculated Values	2011	2012	2013	2014	2015	2016
COG	$100.00	$131.34	$205.05	$157.00	$94.08	$124.69
S&P 500	$100.00	$116.00	$153.58	$174.60	$177.01	$198.18
Dow Jones U.S. Exploration & Production	$100.00	$105.82	$139.52	$124.48	$94.94	$118.19

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

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ITEM 6. SELECTED FINANCIAL DATA

The following table summarizes our selected consolidated financial data for the periods indicated. This information should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7, and the Consolidated Financial Statements and related Notes in Item 8.

	Year Ended December 31,				
(In thousands, except per share amounts)	2016	2015	2014	2013	2012
Statement of Operations Data					
Operating revenues	$1,155,677	$1,357,150	$2,173,011	$1,746,278	$1,204,546
Impairment of oil and gas properties and other assets (1)	435,619	114,875	771,037	—	—
Gain (loss) on sale of assets(2)	(1,857)	3,866	17,120	21,351	50,635
Income (loss) from operations	(566,554)	(90,362)	106,186	551,582	306,186
Net income (loss)	(417,124)	(113,891)	104,468	279,773	131,730
Basic earnings (loss) per share	$(0.91)	$(0.28)	$0.25	$0.67	$0.31
Diluted earnings (loss) per share	$(0.91)	$(0.28)	$0.25	$0.66	$0.31
Dividends per common share	$0.08	$0.08	$0.08	$0.06	$0.04

	December 31,				
(In thousands)	2016	2015	2014	2013	2012
Balance Sheet Data					
Properties and equipment, net	$4,250,125	$4,976,879	$4,925,711	$4,546,227	$4,310,977
Total assets (3)	5,122,569	5,253,038	5,429,705	4,978,038	4,612,780
Current portion of long-term debt	—	20,000	—	—	75,000
Long-term debt (3)	1,520,530	1,996,139	1,743,989	1,143,958	1,008,467
Stockholders' equity	2,567,667	2,009,188	2,142,733	2,204,602	2,131,447

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(1) For discussion of impairment of oil and gas properties and other assets, refer to Note 3 of the Notes to the Consolidated Financial Statements.

(2) Gain on sale of assets in 2014 includes a $19.9 million gain from the sale of certain proved and unproved oil and gas properties located in east Texas. Gain on sale of assets in 2013 includes a $19.4 million gain from the sale of certain proved and unproved oil and gas properties located in the Oklahoma and Texas panhandles, and a $17.5 million loss from the sale of certain proved and unproved oil and gas properties located in Oklahoma, Texas and Kansas and an aggregate net gain of $19.5 million from the sale of various other oil and gas properties during the year. Gain on sale of assets in 2012 includes a $67.0 million gain from the sale of certain Pearsall Shale undeveloped leaseholds in south Texas and an $18.2 million loss from the sale of certain proved oil and gas properties located in south Texas.

(3) Effective January 1, 2016, the Company adopted Accounting Standards Update No. 2015-03 as a change in accounting principle. The Consolidated Balance Sheet as of December 31, 2015, 2014, 2013 and 2012 has been retrospectively adjusted to reflect the adoption of this guidance, resulting in a decrease of $8.9 million, $8.0 million, $3.0 million and $3.5 million, respectively, in both total assets and long-term debt related to the debt issuance costs on the Company's senior notes.

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

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K contain additional information that should be referred to when reviewing this material.

OVERVIEW

Financial and Operating Overview

Financial and operating results for the year ended December 31, 2016 compared to the year ended December 31, 2015 are as follows:

- Equivalent production increased 24.6 Bcfe, or 4%, from 602.5 Bcfe, or 1,650.8 Mmcfe per day, in 2015 to 627.1 Bcfe, or 1,713.4 Mmcfe per day, in 2016.
- Natural gas production increased 34.4 Bcf, or 6%, from 566.0 Bcf in 2015 to 600.4 Bcf in 2016, as a result of drilling and completion activities in Pennsylvania, partially offset by the divestiture of certain oil and gas properties in east Texas in early 2016.
- Crude oil/condensate/NGL production decreased 1.6 Mmbbls, or 27%, from 6.1 Mmbbls in 2015 to 4.5 Mmbbls in 2016, as a result of a decrease in drilling activities in south Texas.
- Average realized natural gas price for 2016 was $1.70 per Mcf, 21% lower than the $2.15 per Mcf price realized in 2015.
- Average realized crude oil price for 2016 was $37.30 per Bbl, 18% lower than the $45.72 per Bbl price realized in 2015.
- Drilled 40 gross wells (38.0 net) with a success rate of 100.0% in 2016 compared to 138 gross wells (130.5 net) with a success rate of 100.0% in 2015.
- Completed 76 gross wells (76.0 net) in 2016 compared to 107 gross wells (98.9 net) in 2015.
- Total capital expenditures were $372.5 million in 2016 compared to $773.5 million in 2015.
- Average rig count during 2016 was approximately 1.1 rigs in the Marcellus Shale and approximately 0.3 rigs in the Eagle Ford Shale, compared to an average rig count in the Marcellus Shale of approximately 3.5 rigs and approximately 1.9 rigs in the Eagle Ford Shale during 2015.
- In February 2016, we completed a public offering of our common stock and received net proceeds of $995.6 million, after deducting underwriting discounts and commissions.
- In February 2016, we received proceeds of $50.1 million primarily related to the divestiture of certain proved and unproved oil and gas properties in east Texas.
- In May 2016, we repurchased $64.0 million principal amount of our 6.51% weighted-average senior notes for approximately $68.3 million.
- In December 2016, we recognized an impairment loss of $435.6 million associated with our oil and gas properties and related pipeline assets in West Virginia and Virginia.

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by pipeline capacity constraints, inventory storage levels, basis differentials, weather conditions and other factors. In addition, our realized prices are further impacted by our hedging activities. As a result, we cannot accurately predict future commodity prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital program, production volumes or revenues. Location differentials have increased in certain regions, such as in the Appalachian region, resulting in further declines in natural gas prices. We expect natural gas and crude oil prices to remain volatile. In addition to production volumes and commodity prices, finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success. For information about the impact of realized commodity prices on our natural gas and crude

oil and condensate revenues, refer to "Results of Operations" below. See "Risk Factors—Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business" and "Risk Factors—Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable" in Item 1A.

We account for our derivative instruments on a mark-to-market basis with changes in fair value recognized in operating revenues in the Consolidated Statement of Operations. As a result of these mark-to-market adjustments associated with our derivative instruments, we will experience volatility in our earnings due to commodity price volatility. Refer to "Impact of Derivative Instruments on Operating Revenues" below and Note 6 to the Consolidated Financial Statements for more information.

Commodity prices have remained volatile and have improved during the fourth quarter of 2016 compared to the fourth quarter of 2015 but have yet to recover to levels experienced in 2014. In the event that commodity prices significantly decline, management would test the recoverability of the carrying value of its oil and gas properties and, if necessary, record an impairment charge.

We believe we are well-positioned to manage the challenges presented in the current commodity pricing environment, and we can endure the current cyclical downturn in the oil and gas industry and the continued volatility in current and future commodity prices by:

- Continuing to exercise discipline in our capital program by fully funding our capital expenditures with operating cash flows.
- Continuing to optimize our drilling, completion and operational efficiencies, resulting in lower operating costs per unit of production.
- Continuing to manage our balance sheet, which included the issuance of common stock in February 2016. Our common stock issuance allowed us to pay down the outstanding balance under our revolving credit facility and certain of our senior notes, leaving us with sufficient availability under our revolving credit facility and existing cash balances to meet our capital requirements and maintain compliance with our debt covenants.
- Continuing to manage price risk by strategically hedging our natural gas and crude oil production.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2016 were from funds generated from the sale of common stock, the sale of natural gas and oil production and proceeds from the sale of assets. These cash flows were primarily used to fund our capital expenditures (including contributions to our equity method investments), repayment of indebtedness under our revolving credit facility and to repurchase certain of our senior notes, interest payments on debt and payment of dividends. See below for additional discussion and analysis of cash flow.

In February 2016, we sold an aggregate of 50.6 million shares of common stock at a price of $19.675 per share and received $995.6 million in net proceeds, after deducting underwriting discounts and commissions. These net proceeds were used for general corporate purposes, including repaying indebtedness under our revolving credit facility, repurchasing certain of our senior notes.

The borrowing base under the terms of our revolving credit facility is redetermined annually in April. In addition, either we or the banks may request an interim redetermination twice a year or in connection with certain acquisitions or divestitures of oil and gas properties. Effective April 19, 2016, our borrowing base was reduced from $3.4 billion to $3.2 billion. The maximum credit amount under the revolving credit facility remained unchanged at $1.8 billion; however, the available commitments were reduced to $1.6 billion at the time of redetermination.

In May 2016, we repurchased $64.0 million principal amount of our 6.51% weighted-average senior notes for approximately $68.3 million. A $4.7 million extinguishment loss was recognized in the second quarter of 2016 associated with the premium paid and the write-off of a portion of the related deferred financing costs due to early repayment. As a result of the repurchase of these senior notes, the available commitments under the revolving credit facility increased to $1.7 billion and remained at that level as of December 31, 2016.

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A decline in commodity prices could result in the future reduction of our borrowing base and related commitments under the revolving credit facility. Unless commodity prices decline significantly from current levels, we do not believe that any such reductions would have a significant impact on our ability to service our debt and fund our drilling program and related operations.

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. We believe that, with the existing cash on hand, internally generated cash flow and availability under our revolving credit facility, we have the capacity to finance our spending plans.

As of December 31, 2016, we had no borrowings outstanding and unused commitments of $1.7 billion under our revolving credit facility. At December 31, 2015, we had $413.0 million of borrowings outstanding under our revolving credit facility.

At December 31, 2016, we were in compliance with all restrictive financial covenants for both the revolving credit facility and senior notes. See Note 5 of the Notes to the Consolidated Financial Statements for further details regarding our debt.

Cash Flows

Our cash flows from operating activities, investing activities and financing activities are as follows:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Cash flows provided by operating activities	$392,377	$740,737	$1,236,435
Cash flows used in investing activities	(353,218)	(993,334)	(1,664,840)
Cash flows provided by financing activities	458,869	232,157	425,959
Net increase (decrease) in cash and cash equivalents	$498,028	$(20,440)	$(2,446)

Operating Activities. Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes and operating expenses. Prices for natural gas and crude oil have historically been volatile, primarily as a result of supply and demand for natural gas and crude oil, pipeline infrastructure constraints and seasonal influences. In addition, fluctuations in cash flow may result in an increase or decrease in our capital expenditures. See "Results of Operations" for a review of the impact of prices and volumes on revenues.

Our working capital is substantially influenced by the variables discussed above and fluctuates based on the timing and amount of borrowings and repayments under our revolving credit facility, the timing of cash collections and payments on our trade accounts receivable and payable, respectively, sales of our securities and changes in the fair value of our commodity derivative activity. From time to time, our working capital will reflect a deficit, while at other times it will reflect a surplus. This fluctuation is not unusual. At December 31, 2016 and 2015, we had a working capital surplus of $458.1 million and a deficit of $90.8 million, respectively. We believe we have adequate liquidity and availability under our revolving credit facility available to meet our working capital requirements over the next twelve months.

Net cash provided by operating activities in 2016 decreased by $348.4 million when compared to 2015. This decrease was primarily due to unfavorable changes in working capital and other assets and liabilities and lower operating revenues, partially offset by lower operating expenses (excluding non-cash expenses). The decrease in operating revenues was primarily due to a decrease in realized natural gas and crude oil prices, partially offset by an increase in equivalent production. Average realized natural gas and crude oil prices decreased by 21% and 18%, respectively, for 2016 compared to 2015. Equivalent production increased by 4% for 2016 over 2015 as a result of higher natural gas production in the Marcellus Shale, partially offset by lower oil production in the Eagle Ford Shale.

Net cash provided by operating activities in 2015 decreased by $495.7 million when compared to 2014. This decrease was primarily due to lower operating revenues and higher operating expenses (excluding non-cash expenses), partially offset by favorable changes in working capital and other assets and liabilities. The decrease in operating revenues was primarily due to a decrease in realized natural gas and crude oil prices, partially offset by an increase in equivalent production. Average realized natural gas and crude oil prices decreased by 34% and 48%, respectively, for 2015 compared to 2014. Equivalent production volumes increased by 13% for 2015 over 2014 as a result of higher natural gas production in the Marcellus Shale and higher oil production in the Eagle Ford Shale.

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See "Results of Operations" for additional information relative to commodity price, production and operating expense fluctuations. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities.

Investing Activities. Cash flows used in investing activities decreased by $640.1 million from 2015 to 2016 due to a decrease of $580.4 million in capital expenditures, $16.3 million lower acquisition costs and $42.8 million higher proceeds from the sale of assets.

Cash flows used in investing activities decreased by $671.5 million from 2014 to 2015 due to a decrease of $524.0 million in capital expenditures, $198.4 million lower acquisition costs and a $9.0 million decrease in capital contributions associated with our equity method investments. These decreases were partially offset by a $31.8 million decrease in proceeds from the sale of assets and $28.1 million of changes in restricted cash balances.

Financing Activities. Cash flows provided by financing activities increased by $226.7 million from 2015 to 2016 due to $995.3 million of net proceeds related to the issuance of common stock and lower capitalized debt issuance costs of $4.6 million related to the amendment of our revolving credit facility and senior notes in December 2015. These increases were partially offset by $770.0 million of higher net repayments of debt due to the repayment of the outstanding balance on our revolving credit facility and certain of our senior notes with the proceeds from the issuance of common stock and $3.1 million of higher dividend payments.

Cash flows provided by financing activities decreased by $193.8 million from 2014 to 2015 due to $332.0 million of lower net borrowings and an increase in cash paid for capitalized debt issuance costs of $2.2 million related to the amendment of our credit facility in April 2015. These decreases were partially offset by lower treasury stock repurchases of $138.9 million as no shares were repurchased in 2015 and a decrease of $1.4 million in tax benefits associated with our stock-based compensation.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(Dollars in thousands)	2016	2015
Debt[(1)]	$1,520,530	$2,016,139
Stockholders' equity	2,567,667	2,009,188
Total capitalization	$4,088,197	$4,025,327
Debt to total capitalization	37 %	50 %
Cash and cash equivalents	$498,542	$514

(1) Includes $20.0 million of current portion of long-term debt and $413.0 million of borrowings outstanding under our revolving credit facility at December 31, 2015. There were no borrowings outstanding under our revolving credit facility as of December 31, 2016.

During 2016 and 2015, we paid dividends of $36.2 million ($0.08 per share) and $33.1 million ($0.08 per share) on our common stock, respectively.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital expenditures, excluding any significant property acquisitions, with cash generated from operations and, if required, borrowings under our revolving credit facility. We budget these expenditures based on our projected cash flows for the year.

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The following table presents major components of our capital and exploration expenditures:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Capital expenditures			
Drilling and facilities	$359,479	$729,994	$1,454,288
Leasehold acquisitions	2,703	20,097	73,962
Property acquisitions	—	16,312	214,737
Pipeline and gathering	1,909	2,373	1,287
Other	8,386	4,739	14,791
	372,477	773,515	1,759,065
Exploration expenditures(1)	27,662	27,460	28,746
Total	$400,139	$800,975	$1,787,811

(1) Exploration expenditures include $10.1 million, $3.3 million and $7.8 million of exploratory dry hole expenditures in 2016, 2015 and 2014, respectively.

In 2016, we drilled 40 gross wells (38.0 net) and completed 76 gross wells (76.0 net), of which 62 gross wells (62.0 net) were drilled but uncompleted in prior years. In 2017, we plan to drill 95 gross wells (90.0 net) and complete 95 gross wells (90.0 net), of which 51 gross wells (45.0 net) were drilled but uncompleted in prior years. Our 2017 drilling program includes approximately $650.0 million in total capital expenditures. We will continue to assess the natural gas and crude oil price environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. A summary of our contractual obligations as of December 31, 2016 are set forth in the following table:

		Payments Due by Year			
(In thousands)	Total	2017	2018 to 2019	2020 to 2021	2022 & Beyond
Debt	$1,528,000	$—	$304,000	$275,000	$949,000
Interest on debt(1)	402,296	73,511	117,643	89,593	121,549
Transportation and gathering agreements(2)	1,844,173	148,061	323,653	300,632	1,071,827
Drilling rig commitments(2)	4,188	4,188	—	—	—
Hydraulic fracturing services commitments (2)	3,960	3,960	—	—	—
Operating leases(2)	37,209	7,244	13,090	10,672	6,203
Equity investment contribution commitments(3)	266,363	70,000	196,363	—	—
Total contractual obligations	$4,086,189	$306,964	$954,749	$675,897	$2,148,579

(1) Interest payments have been calculated utilizing the rates associated with our senior notes outstanding at December 31, 2016, assuming that our senior notes will remain outstanding through their respective maturity dates.

(2) For further information on our obligations under transportation and gathering agreements, drilling rig commitments, hydraulic fracturing services commitments and operating leases, see Note 9 of the Notes to the Consolidated Financial Statements.

(3) For further information on our equity investment contribution commitments, see Note 4 of the Notes to the Consolidated Financial Statements.

Amounts related to our asset retirement obligation are not included in the above table given the uncertainty regarding the actual timing of such expenditures. The total amount of our asset retirement obligation at December 31, 2016 was $133.7 million. See Note 8 of the Notes to the Consolidated Financial Statements for further details.

We have no off-balance sheet debt or other similar unrecorded obligations.

Potential Impact of Our Critical Accounting Policies

Our significant accounting policies are described in Note 1 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements, which is in accordance with accounting principles generally accepted in the United States, requires management to make certain estimates and judgments that affect the amounts reported in our financial statements and the related disclosures of assets and liabilities. The following accounting policies are our most critical policies requiring more significant judgments and estimates. We evaluate our estimates and assumptions on a regular basis. Actual results could differ from those estimates.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for our oil and gas producing activities. Acquisition costs for proved and unproved properties are capitalized when incurred. Judgment is required to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of costs incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole costs are expensed. Development costs, including costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations and judgment of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and crude oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Any significant variance in the interpretations or assumptions could materially affect the estimated quantity and value of our reserves and can change substantially over time. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of reservoir performance, drilling activity, commodity prices, fluctuations in operating expenses, technological advances, new geological or geophysical data or other economic factors. Accordingly, reserve estimates are generally different from the quantities ultimately recovered. We cannot predict the amounts or timing of such future revisions.

Our reserves have been prepared by our petroleum engineering staff and audited by Miller and Lents, independent petroleum engineers, who in their opinion determined the estimates presented to be reasonable in the aggregate. For more information regarding reserve estimation, including historical reserve revisions, refer to the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8.

Our rate of recording depreciation, depletion and amortization (DD&A) expense is dependent upon our estimate of proved and proved developed reserves, which are utilized in our unit-of-production calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it uneconomic to drill and produce higher cost fields. A 5% positive or negative revision to proved reserves would result in a decrease of $0.04 per Mcfe and an increase of $0.04 per Mcfe, respectively, on our DD&A rate. Revisions in significant fields may individually affect our DD&A rate. It is estimated that a positive or negative reserve revision of 10% in one of our most productive fields would result in a decrease of $0.05 per Mcfe and an increase of $0.06 per Mcfe, respectively, on our total DD&A rate. These estimated impacts are based on current data, and actual events could require different adjustments to our DD&A rate.

In addition, a decline in proved reserve estimates may impact the outcome of our impairment test under applicable accounting standards. Due to the inherent imprecision of the reserve estimation process, risks associated with the operations of proved producing properties and market sensitive commodity prices utilized in our impairment analysis, management cannot determine if an impairment is reasonably likely to occur in the future.

Carrying Value of Oil and Gas Properties

We evaluate our proved oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future natural

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gas and crude oil prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process, historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. In the event that commodity prices significantly decline, management would test the recoverability of the carrying value of its oil and gas properties and, if necessary, record an impairment charge. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and oil.

Unproved oil and gas properties are assessed periodically for impairment on an aggregate basis through periodic updates to our undeveloped acreage amortization based on past drilling and exploration experience, our expectation of converting leases to held by production and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. Historically, the average property life in each of the geographical areas has not significantly changed and generally range from three to five years. The commodity price environment may impact the capital available for exploration projects as well as development drilling. We have considered these impacts when determining the amortization rate of our undeveloped acreage, especially in exploratory areas. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately $8.9 million or decrease by approximately $7.5 million, respectively, per year.

As these properties are developed and reserves are proved, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved properties are written off depends on the timing and success of our future exploration and development program.

Asset Retirement Obligations

The majority of our asset retirement obligations (ARO) relates to the plugging and abandonment of oil and gas wells and to a lesser extent meter stations, pipelines, processing plants and compressors. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. The recognition of an asset retirement obligation requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate. In periods subsequent to initial measurement, the asset retirement cost is depreciated using the units-of-production method, while increases in the discounted ARO liability resulting from the passage of time (accretion expense) are reflected as depreciation, depletion and amortization expense.

Accounting for Derivative Instruments and Hedging Activities

Under applicable accounting standards, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each quarterly period, these instruments are marked-to-market. The change in fair value of derivatives not designated as hedges and the ineffective portion of the change in the fair value of derivatives designated as cash flow hedges and are recorded as a component of operating revenues in gain (loss) on derivative instruments in the Consolidated Statement of Operations. The change in the fair value of derivatives designated as cash flow hedges that are effective are recorded in accumulated other comprehensive income (loss) in stockholders' equity in the Consolidated Balance Sheet.

Our derivative contracts are measured based on quotes from our counterparties. Such quotes have been derived using an income approach that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, basis differentials, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term, as applicable. These estimates are verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness. The determination of fair value also incorporates a credit adjustment for non-performance risk. We measure the non-performance risk of our counterparties by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while our non-performance risk is evaluated using a market credit spread provided by one of our banks.

Our financial condition, results of operations and liquidity can be significantly impacted by changes in the market value of our derivative instruments due to volatility of natural gas and crude oil prices, both NYMEX and basis differentials.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments include the calculation of certain deferred tax assets and liabilities that arise from differences in the timing and recognition of revenue and expenses for tax and financial reporting purposes and estimating reserves for potential adverse outcomes regarding tax positions that we have taken. We account for the uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

We believe all of our deferred tax assets, net of any valuation allowances, will ultimately be realized, taking into consideration our forecasted future taxable income, which includes consideration of future operating conditions specifically related to commodity prices. If our estimates and judgments change regarding our ability to realize our deferred tax assets, our tax provision could increase in the period it is determined that it is more likely than not it will not be realized.

Our effective tax rate is subject to variability as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which could affect us. Our effective tax rate is affected by changes in the allocation of property, payroll and revenues among states in which we operate. A small change in our estimated future tax rate could have a material effect on current period earnings.

Contingency Reserves

A provision for contingencies is charged to expense when the loss is probable and the cost is estimable. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. In certain cases, management's judgment is based on the advice and opinions of legal counsel and other advisors, the interpretation of laws and regulations, which can be interpreted differently by regulators and courts of laws, our experience and the experiences of other companies dealing with similar matters, and our decision on how we intend to respond to a particular matter. Actual losses can differ from estimates for various reasons, including those noted above. We monitor known and potential legal, environmental and other contingencies and make our best estimate based on the information we have. Future changes in facts and circumstances not currently foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

Stock-Based Compensation

We account for stock-based compensation under the fair value method of accounting in accordance with applicable accounting standards. Under the fair value method, compensation cost is measured at the grant date for equity-classified awards and remeasured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is generally the vesting period. To calculate fair value, we use either a Monte Carlo or Black-Scholes valuation model, as determined by the specific provisions of the award. The use of these models requires significant judgment with respect to expected life, volatility and other factors. Stock-based compensation cost for all types of awards is included in general and administrative expense in the Consolidated Statement of Operations. See Note 13 of the Notes to the Consolidated Financial Statements for a full discussion of our stock-based compensation.

Recently Adopted Accounting Pronouncements

Refer to Note 1 of the Notes to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for a discussion of recently adopted accounting pronouncements.

Recently Issued Accounting Pronouncements

Refer to Note 1 of the Notes to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for a discussion of new accounting pronouncements that affect us.

OTHER ISSUES AND CONTINGENCIES

Regulations. Our operations are subject to various types of regulation by federal, state and local authorities. See "Regulation of Oil and Natural Gas Exploration and Production," "Natural Gas Marketing, Gathering and

Transportation," "Federal Regulation of Swap Transactions," "Federal Regulation of Petroleum," "Pipeline Safety Regulation," and "Environmental and Safety Regulations" in the "Other Business Matters" section of Item 1 for a discussion of these regulations.

Restrictive Covenants. Our ability to incur debt and to make certain types of investments is subject to certain restrictive covenants in our various debt instruments. Among other requirements, our senior note agreements and our revolving credit agreement specify a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of 2.8 to 1.0, a minimum asset coverage ratio of the present value of proved reserves before income taxes plus adjusted cash to indebtedness and other liabilities of 1.25 to 1.0, which increases back to a ratio of 1.75 to 1.0 beginning on January 1, 2018, and a leverage ratio of debt to consolidated EBITDAX of 4.75 to 1.0. through and including December 31, 2016. Under the terms of the respective agreements, the leverage ratio will be adjusted to 4.25 to 1.0 through and including December 31, 2017 and 3.5 to 1.0 beginning on March 31, 2018 or until we maintain a leverage ratio below 3.0 to 1.0 for two consecutive fiscal quarters on or after December 31, 2017 or we receive an investment grade rating by Standard & Poor's Ratings Services (S&P) or Moody's Investor Service, Inc. (Moody's), at which time we will no longer be subject to this covenant. Our revolving credit agreement also requires us to maintain a minimum current ratio of 1.0 to 1.0. At December 31, 2016, we were in compliance with all restrictive financial covenants in both our senior note agreements and our revolving credit agreement.

Operating Risks and Insurance Coverage. Our business involves a variety of operating risks. See "Risk Factors—We face a variety of hazards and risks that could cause substantial financial losses" in Item 1A. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. The costs of these insurance policies are somewhat dependent on our historical claims experience, the areas in which we operate and market conditions.

Commodity Pricing and Risk Management Activities. Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and crude oil. Further declines in natural gas and crude oil prices may have a material adverse effect on our financial condition, liquidity, ability to obtain financing and operating results. Lower natural gas and crude oil prices also may reduce the amount of natural gas and crude oil that we can produce economically. Historically, natural gas and crude oil prices have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results. In particular, substantially lower prices would significantly reduce revenue and could potentially trigger an impairment of our oil and gas properties or a violation of certain financial debt covenants. Because our reserves are predominantly natural gas (approximately 97% of equivalent proved reserves), changes in natural gas prices may have a more significant impact on our financial results than oil prices.

The majority of our production is sold at market responsive prices. Generally, if the related commodity index declines, the price that we receive for our production will also decline. Furthermore, we have experienced widening basis differentials in certain regions, such as in the Appalachian region, resulting in further declines in natural gas prices. Therefore, the amount of revenue that we realize is determined by certain factors that are beyond our control. However, management may mitigate this price risk on a portion of our anticipated production with the use of commodity derivatives. Most recently, we have used commodity derivatives such as collar, swap and basis swap arrangements to reduce the impact of sustained lower pricing on our revenue. Under both arrangements, there is also a risk that the movement of index prices may result in our inability to realize the full benefit of an improvement in market conditions.

RESULTS OF OPERATIONS

2016 and 2015 Compared

We reported a net loss for 2016 of $417.1 million, or $0.91 per share, compared to net loss for 2015 of $113.9 million, or $0.28 per share. The increase in net loss was primarily due to lower operating revenues and higher operating expenses, partially offset by a higher income tax benefit.

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Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
Revenue Variances (In thousands)	2016	2015	Amount	Percent
Natural gas	$1,022,590	$1,025,044	$(2,454)	— %
Crude oil and condensate	151,106	248,211	(97,105)	(39)%
Gain (loss) on derivative instruments	(38,950)	56,686	(95,636)	(169)%
Brokered natural gas	13,569	16,383	(2,814)	(17)%
Other	7,362	10,826	(3,464)	(32)%
	$1,155,677	$1,357,150	$(201,473)	(15)%

	Year Ended December 31,		Variance		Increase (Decrease)
	2016	2015	Amount	Percent	(In thousands)
Price Variances					
Natural gas	$1.70	$1.81	$(0.11)	(6)%	$(64,718)
Crude oil and condensate	$37.65	$45.72	$(8.07)	(18)%	(32,365)
Total					$(97,083)
Volume Variances					
Natural gas (Bcf)	600.4	566.0	34.4	6 %	$62,264
Crude oil and condensate (Mbbl)	4,013	5,429	(1,416)	(26)%	(64,740)
Total					$(2,476)

Natural Gas Revenues

The decrease in natural gas revenues of $2.5 million was due to lower natural gas prices, partially offset by higher production. The increase in production was a result of our drilling and completion activities in Pennsylvania, partially offset by the divestiture of certain oil and gas properties in east Texas in early 2016.

Crude Oil and Condensate Revenues

The decrease in crude oil and condensate revenues of $97.1 million was due to lower production and crude oil prices. The decrease in production was a result of a decrease in drilling and completion activities in south Texas.

Impact of Derivative Instruments on Operating Revenues

	Year Ended December 31,	
(In thousands)	2016	2015
Cash received (paid) on settlement of derivative instruments		
Gain (loss) on derivative instruments	$(1,682)	$194,289
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	(37,268)	(137,603)
	$(38,950)	$56,686

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Brokered Natural Gas

	Year Ended December 31,		Variance		Price and Volume Variances (In thousands)
	2016	2015	Amount	Percent	
Brokered Natural Gas Sales					
Sales price ($/Mcf)	$2.55	$2.83	$(0.28)	(10)%	$(1,490)
Volume brokered (Mmcf)	x5,321	x5,784	(463)	(8)%	(1,324)
Brokered natural gas (In thousands)	$13,569	$16,383			$(2,814)
Brokered Natural Gas Purchases					
Purchase price ($/Mcf)	$2.03	$2.18	$(0.15)	(7)%	$798
Volume brokered (Mmcf)	x5,321	x5,784	(463)	(8)%	1,009
Brokered natural gas (In thousands)	$10,785	$12,592			$1,807
Brokered natural gas margin (In thousands)	$2,784	$3,791			$(1,007)

The $1.0 million decrease in brokered natural gas margin is a result of a decrease in sales price that outpaced the decrease in purchase price and lower brokered volumes.

Operating and Other Expenses

	Year Ended December 31,		Variance	
(In thousands)	2016	2015	Amount	Percent
Operating and Other Expenses				
Direct operations	$100,696	$140,814	$(40,118)	(28)%
Transportation and gathering	436,542	427,588	8,954	2%
Brokered natural gas	10,785	12,592	(1,807)	(14)%
Taxes other than income	29,223	42,809	(13,586)	(32)%
Exploration	27,662	27,460	202	1%
Depreciation, depletion and amortization	590,128	622,211	(32,083)	(5)%
Impairment of oil and gas properties and other assets	435,619	114,875	320,744	279%
General and administrative	87,242	69,444	17,798	26%
	$1,717,897	$1,457,793	$260,104	18%
Earnings (loss) on equity method investments	$(2,477)	$6,415	$(8,892)	(139)%
Gain (loss) on sale of assets	(1,857)	3,866	(5,723)	(148)%
Loss on debt extinguishment	4,709	—	4,709	100%
Interest expense	88,336	96,911	(8,575)	(9)%
Income tax benefit	(242,475)	(73,382)	169,093	230%

Total costs and expenses from operations increased by $260.1 million from 2015 to 2016. The primary reasons for this fluctuation are as follows:

- Direct operations decreased $40.1 million largely due to improved operational efficiencies, cost reductions from service providers and suppliers in 2016 compared to 2015 and divestiture of certain oil and gas properties in east Texas in February 2016.
- Transportation and gathering increased $9.0 million due to higher throughput as a result of higher Marcellus Shale production and the commencement of various transportation and gathering agreements in the Marcellus Shale throughout 2015.

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- Brokered natural gas decreased $1.8 million from 2015 to 2016. See the preceding table titled "Brokered Natural Gas" for further analysis.
- Taxes other than income decreased $13.6 million due to $7.2 million lower production taxes resulting from lower crude oil prices and production in south Texas and the receipt of a production tax refund of $1.9 million in February 2016. Additionally, drilling impact fees decreased $1.5 million as a result of drilling fewer wells in Pennsylvania during 2016 compared to 2015 and ad valorem taxes decreased $3.8 million as a result of lower property values primarily in south Texas. The remaining changes were not individually significant.
- Exploration increased $0.2 million as a result of a $6.7 million increase in exploratory dry hole expense, partially offset by lower charges related to the release of certain drilling rig contracts in south Texas and $2.7 million lower geophysical and geological costs and other exploration expenses. During 2016, we recorded rig termination charges of $1.7 million, compared to $5.1 million during 2015.
- Depreciation, depletion and amortization decreased $32.1 million, of which $41.2 million was due to a lower DD&A rate of $0.87 per Mcfe for 2016 compared to $0.93 per Mcfe for 2015, partially offset by a $23.0 million increase due to higher equivalent production volumes. The lower DD&A rate was primarily due to lower cost reserve additions and the impairment charge recorded in the fourth quarter of 2015 associated with higher DD&A rate fields. In addition, amortization of unproved properties decreased $16.4 million in 2016 as a result of lower lease acquisition costs and lower amortization rates.
- Impairment of oil and gas properties and other assets was $435.6 million in 2016 due to the impairment of oil and gas properties and related pipeline assets in West Virginia and Virginia. In 2015, we recognized an impairment of oil and gas properties of $114.9 million related to certain non-core fields in south Texas, east Texas and Louisiana. The impairment of these fields was due to a significant decline in commodity prices in late 2015.
- General and administrative increased $17.8 million due to higher stock-based compensation expense of $12.3 million primarily the result of an increase in the Company's stock price during 2016 compared to 2015 and $2.7 million higher professional services. The remaining changes were not individually significant.

Earnings (Loss) on Equity Method Investments

The decrease in equity method earnings (loss) is the result of our proportionate share of net earnings from our equity method investments in 2016 compared to 2015.

Gain (Loss) on Sale of Assets

During 2016, we recognized a net aggregate loss of $1.9 million primarily due to the sale of certain of our oil and gas properties in east and south Texas. During 2015, we recognized a net aggregate gain of $3.9 million primarily due to the sale of certain unproved oil and gas properties in east Texas.

Loss on Debt Extinguishment

A $4.7 million extinguishment loss was recognized in the second quarter of 2016 related to the premium paid for the repurchase of a portion of our 6.51% weighted-average senior notes in May 2016 and the write-off of a portion of the associated deferred financing costs due to early repayment.

Interest Expense

Interest expense decreased $8.6 million due to a $5.5 million decrease resulting from the repayment of the outstanding borrowings under our revolving credit facility in March 2016, which remained undrawn through December 31, 2016. Interest expense also decreased $3.4 million resulting from the repurchase of a portion of our 6.51% weighted-average senior notes in May 2016 and the repayment of our 7.33% weighted-average senior notes at maturity. These decreases were offset by a $0.6 million increase in commitment fees as a result of an increase in the unused portion of the commitments under our revolving credit facility.

Income Tax Benefit

Income tax benefit increased $169.1 million due to a higher pretax loss, partially offset by a lower effective tax rate. The effective tax rates for 2016 and 2015 were 36.8% and 39.2%, respectively. The decrease in the effective tax rate is primarily due to the impact of non-recurring discrete items recorded during 2016 compared to 2015.

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We expect our 2017 effective income tax rate to be approximately 37.0%; however, this rate may fluctuate based on a number of factors, including but not limited to changes in enacted federal and/or state tax rates that occur during the year, as well as changes in the composition and location of our asset base, our employees and our customers.

2015 and 2014 Compared

We reported a net loss for 2015 of $113.9 million, or $0.28 per share, compared to net income for 2014 of $104.5 million, or $0.25 per share. The decrease in net income was primarily due to lower operating revenues, higher operating and interest expenses and a decrease in gain on sale of assets. These decreases were partially offset by lower impairments on oil and gas properties.

Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
Revenue Variances (In thousands)	2015	2014	Amount	Percent
Natural gas	$1,025,044	$1,590,625	$(565,581)	(36)%
Crude oil and condensate	248,211	313,889	(65,678)	(21)%
Gain (loss) on derivative instruments	56,686	219,319	(162,633)	(74)%
Brokered natural gas	16,383	34,416	(18,033)	(52)%
Other	10,826	14,762	(3,936)	(27)%
	$1,357,150	$2,173,011	$(815,861)	(38)%

	Year Ended December 31,		Variance		Increase (Decrease)
	2015	2014	Amount	Percent	(In thousands)
Price Variances					
Natural gas[(1)]	$1.81	$3.13	$(1.32)	(42)%	$(747,121)
Crude oil and condensate[(2)]	$45.72	$87.48	$(41.76)	(48)%	(226,729)
Total					$(973,850)
Volume Variances					
Natural gas (Bcf)	566.0	508.0	58.0	11 %	$181,540
Crude oil and condensate (Mbbl)	5,429	3,588	1,841	51 %	161,051
Total					$342,591

(1) Prices in 2014 include the impact of cash flow hedge settlements during the period, which decreased the price by $0.28 per Mcf. There was no impact in 2015.

(2) Prices in 2014 include the impact of cash flow hedge settlements during the period, which decreased the price by $0.17 per Bbl. There was no impact in 2015.

Natural Gas Revenues

The decrease in natural gas revenues of $565.6 million was due to lower natural gas prices, partially offset by higher production associated with the positive results of our Marcellus Shale drilling program in Pennsylvania.

Crude Oil and Condensate Revenues

The decrease in crude oil and condensate revenues of $65.7 million was due to lower crude oil prices, partially offset by higher production. The increase in production was a result of our oil-focused Eagle Ford Shale drilling program in south Texas and production associated with the south Texas assets acquired in the fourth quarter of 2014.

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Gain (Loss) on Derivative Instruments

Effective April 1, 2014, we elected to discontinue hedge accounting on a prospective basis. Subsequent to April 1, 2014, our derivative instruments were accounted for on a mark-to-market basis. Changes in fair value and cash settlements of derivative instruments are recognized in operating revenues in the Consolidated Statement of Operations.

Impact of Derivative Instruments on Operating Revenues

	Year Ended December 31,	
(In thousands)	2015	2014
Cash received (paid) on settlement of derivative instruments		
Natural gas	$—	$(143,577)
Crude oil and condensate	—	(626)
Gain (loss) on derivative instruments	194,289	81,716
	$194,289	$(62,487)
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	(137,603)	137,603
	$56,686	$75,116

Brokered Natural Gas

	Year Ended December 31,		Variance		Price and Volume Variances
	2015	2014	Amount	Percent	(In thousands)
Brokered Natural Gas Sales					
Sales price ($/Mcf)	$2.83	$4.65	$(1.82)	(39)%	$(10,527)
Volume brokered (Mmcf)	x5,784	x7,402	(1,618)	(22)%	(7,506)
Brokered natural gas (In thousands)	$16,383	$34,416			$(18,033)
Brokered Natural Gas Purchases					
Purchase price ($/Mcf)	$2.18	$4.06	$(1.88)	(46)%	$10,874
Volume brokered (Mmcf)	x5,784	x7,402	(1,618)	(22)%	6,564
Brokered natural gas (In thousands)	$12,592	$30,030			$17,438
Brokered natural gas margin (In thousands)	$3,791	$4,386			$(595)

The $0.6 million decrease in brokered natural gas margin is a result of lower brokered volumes, partially offset by a decrease in purchase price that outpaced the decrease in sales price.

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Operating and Other Expenses

	Year Ended December 31,		Variance	
(In thousands)	2015	2014	Amount	Percent
Operating and Other Expenses				
Direct operations	$140,814	$145,529	$(4,715)	(3)%
Transportation and gathering	427,588	349,321	78,267	22 %
Brokered natural gas	12,592	30,030	(17,438)	(58)%
Taxes other than income	42,809	47,012	(4,203)	(9)%
Exploration	27,460	28,746	(1,286)	(4)%
Depreciation, depletion and amortization	622,211	632,760	(10,549)	(2)%
Impairment of oil and gas properties and other assets	114,875	771,037	(656,162)	(85)%
General and administrative	69,444	82,590	(13,146)	(16)%
	$1,457,793	$2,087,025	$(629,232)	(30)%
Earnings (loss) on equity method investments	$6,415	$3,080	$3,335	108 %
Gain (loss) on sale of assets	3,866	17,120	(13,254)	(77)%
Interest expense	96,911	73,785	23,126	31 %
Income tax benefit	(73,382)	(72,067)	1,315	2 %

Total costs and expenses from operations decreased by $629.2 million from 2014 to 2015. The primary reasons for this fluctuation are as follows:

- Direct operations decreased $4.7 million largely due to cost reductions from suppliers, improved operational efficiencies and lower workover and plugging and abandonment expenses in 2015 compared to 2014. These decreases were partially offset by higher operating costs associated with the south Texas assets acquired in the fourth quarter of 2014.
- Transportation and gathering increased $78.3 million due to higher throughput as a result of higher Marcellus Shale production, higher transportation rates and the commencement of various transportation and gathering agreements throughout 2014.
- Brokered natural gas decreased $17.4 million from 2014 to 2015. See the preceding table titled “Brokered Natural Gas” for further analysis.
- Taxes other than income decreased $4.2 million due to $5.9 million lower production taxes resulting from lower crude oil and condensate revenues and $0.8 million lower drilling impact fees due to a decrease in our Marcellus Shale drilling activities. These decreases were partially offset by $2.0 million higher ad valorem taxes due to increased activity and the assets acquired in the fourth quarter of 2014 in south Texas and $0.6 million higher franchise taxes.
- Exploration decreased $1.3 million as a result of lower exploratory dry hole costs of $4.5 million and $2.4 million lower geophysical and geological and other exploration expenses due to reduced activity. These decreases were partially offset by a $5.1 million charge related to the release of certain drilling rig contracts in south Texas in the first half of 2015.
- Depreciation, depletion and amortization decreased $10.5 million, of which $117.3 million was due to a lower DD&A rate of $0.93 per Mcfe for 2015 compared to $1.13 per Mcfe for 2014, partially offset by $79.9 million due to higher equivalent production volumes. The lower DD&A rate was primarily due to lower cost reserve additions associated with our Marcellus Shale drilling program and the impairment charge recorded in the fourth quarter of 2014 associated with higher DD&A rate fields. In addition, amortization of unproved properties increased $24.0 million as a result of ongoing evaluation of our unproved properties and the acquisition of undeveloped leaseholds in south Texas in late 2014. Accretion expense increased $1.8 million due to the acquisition of proved properties in south Texas in late 2014 and an increase in asset retirement obligations as a result of revisions of previous estimates recorded in fourth quarter 2014.
- Impairment of oil and gas properties and other assets was $114.9 million in 2015 due to the impairment of certain non-core fields in south Texas, east Texas and Louisiana. The impairment of these fields was due to a significant

decline in commodity prices in late 2015. In 2014, we recognized an impairment of oil and gas properties and other assets of

$771.0 million related to certain non-core fields, primarily in east Texas. The impairment of these fields was due to a significant decline in commodity prices in late 2014 and management's decision not to pursue activity in these non-core areas in the then current price environments.

- General and administrative decreased $13.1 million due to lower stock-based compensation expense of $7.8 million primarily due to a decline in the Company's stock price during 2015 compared to 2014 and $1.8 million lower incentive compensation expense. The remaining increase and decreases in other expenses were not individually significant.

Earnings (Loss) on Equity Method Investments

The increase in equity method earnings (loss) is the result of our proportionate share of net earnings from our equity method investments in 2015 compared to 2014.

Gain (Loss) on Sale of Assets

During 2015, we recognized a net aggregate gain of $3.9 million primarily due to the sale of certain unproved oil and gas properties in east Texas. During 2014, we recognized a net aggregate gain of $17.1 million primarily due to the sale of certain proved and unproved oil and gas properties in east Texas.

Interest Expense

Interest expense increased $23.1 million due to $24.1 million of higher interest expense associated with our private placement in September 2014 of $925 million aggregate principal amount of senior notes with a weighted-average interest rate of 3.65% and higher commitment fees on the unused portion of our revolving credit facility of $1.0 million. These increases were partially offset by a decrease in interest expense of $1.7 million associated with our revolving credit facility due to a decrease in weighted-average borrowings based on daily balances of approximately $347.2 million compared to approximately $410.0 million during 2015 and 2014, respectively.

Income Tax Benefit

Income tax benefit increased $1.3 million due to lower pretax income, partially offset by a higher effective tax rate. The effective tax rates for 2015 and 2014 were 39.2% and (222.4)%, respectively. The overall effective tax rate for 2014 was significantly lower due to a change in our effective state income tax rates based on updated state apportionment factors in states in which we operate. The 2014 decrease in our state apportionment factors was primarily driven by a shift in the sourcing of revenues based on the location of customers to whom we ultimately sell our natural gas in the northeast United States. The 2014 decrease in effective state income tax rates significantly affected our estimated net state deferred tax liabilities reflected in our Consolidated Balance Sheet, resulting in an income tax benefit of approximately $87.0 million that was reflected in our provision for income taxes in 2014.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Our primary market risk is exposure to natural gas and crude oil prices. Realized prices are mainly driven by worldwide prices for crude oil and spot market prices for North American natural gas production. Commodity prices can be volatile and unpredictable.

Derivative Instruments and Risk Management Activities

Our risk management strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets through the use of commodity derivatives. A committee that consists of members of senior management oversees our risk management activities. Our commodity derivatives generally cover a portion of our production and provide only partial price protection by limiting the benefit to us of increases in prices, while protecting us in the event of price declines. Further, if any of our counterparties defaulted, this protection might be limited as we might not receive the full benefit of our commodity derivatives. Please read the discussion below as well as Note 6 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our derivative and risk management activities.

Periodically, we enter into commodity derivatives, including collar, swap and basis swap agreements, to protect against exposure to price declines related to our natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity derivatives other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. All of our derivatives are used for risk

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management purposes and are not held for trading purposes. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. Under the swap agreements, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

As of December 31, 2016, we had the following outstanding commodity derivatives:

			Collars						
			Floor		Ceiling		Swaps	Basis Swaps	Asset
Type of Contract	Volume	Contract Period	Range	Weighted-Average	Range	Weighted-Average	Weighted-Average	Weighted-Average	(Liability) (In thousands)
Natural gas	35.5 Bcf	Jan. 2017 - Dec. 2017					$ 3.12		$ (21,682)
Natural gas	16.2 Bcf	Feb. 2017 - Dec. 2017					$ 3.46		(857)
Natural gas	35.5 Bcf	Jan. 2017 - Dec. 2017	$—	$ 3.09	$3.42-$3.45	$ 3.43			(14,289)
Natural gas	21.3 Bcf	Jan. 2018 - Dec. 2019						$ 0.42	2,823
Crude oil	1.8 Mmbbl	Jan. 2017 - Dec. 2017	$—	$ 50.00	$56.25-$56.50	$ 56.39			(3,950)
									$ (37,955)

In the above table, natural gas prices are stated per Mcf and crude oil prices are stated per barrel.

The amounts set forth in the table above represent our total unrealized derivative position at December 31, 2016 and exclude the impact of non-performance risk. Non-performance risk is considered in the fair value of our derivative instruments that are recorded in our Consolidated Financial Statements and is primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while our non-performance risk is evaluated using a market credit spread provided by one of our banks.

A significant portion of our expected natural gas and crude oil production for 2017 and beyond is currently unhedged and directly exposed to the volatility in natural gas and crude oil market prices, whether favorable or unfavorable.

During 2016, natural gas swaps covered 52.0 Bcf, or 9%, of natural gas production at a weighted-average price of $2.51 per Mcf. Crude oil collars with floor prices of $38.00 per Bbl and ceiling prices ranging from $47.10 to $47.50 per Bbl covered 1.4 Mmbbl, or 34%, of crude oil production at a weighted-average price of $45.61 per Bbl.

We are exposed to market risk on commodity derivative instruments to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. Our counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. We perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any losses related to non-performance risk of our counterparties and we do not anticipate any material impact on our financial results due to non-performance by third parties. However, we cannot be certain that we will not experience such losses in the future.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future commodity prices. See "Forward-Looking Information" for further details.

Fair Value of Other Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amount reported in the Consolidated Balance Sheet for cash and cash equivalents approximates fair value due to the short-term maturities of these instruments. Cash and cash equivalents are classified as Level 1 in the fair value hierarchy.

We use available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount we would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our senior notes and revolving credit facility to new issuances (secured and unsecured)

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and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all senior notes and the revolving credit facility is based on interest rates currently available to us.

The carrying amount and fair value of debt is as follows:

	December 31, 2016		December 31, 2015	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$1,520,530	$1,463,643	$2,016,139	$1,839,530
Current maturities	—	—	(20,000)	(20,378)
Long-term debt, excluding current maturities	$1,520,530	$1,463,643	$1,996,139	$1,819,152

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of Cabot Oil & Gas Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive income, stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries (the "Company") at December 31, 2016 and December 31, 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 Management's Report on Internal Control over Financial Reporting under Item 9A. 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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2017

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CABOT OIL & GAS CORPORATION
CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$498,542	$514
Accounts receivable, net	191,045	120,229
Income taxes receivable	10,298	4,323
Inventories	13,304	17,049
Other current assets	2,692	2,671
Total current assets	715,881	144,786
Properties and equipment, net (Successful efforts method)	4,250,125	4,976,879
Equity method investments	129,524	103,517
Other assets	27,039	27,856
	$5,122,569	$5,253,038
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$168,411	$160,407
Current portion of long-term debt	—	20,000
Accrued liabilities	21,492	24,923
Interest payable	27,650	30,222
Derivative instruments	40,259	—
Total current liabilities	257,812	235,552
Long-term debt, net	1,520,530	1,996,139
Deferred income taxes	579,447	807,236
Asset retirement obligations	131,733	143,606
Postretirement benefits	36,259	35,293
Other liabilities	29,121	26,024
Total liabilities	2,554,902	3,243,850
Commitments and contingencies		
Stockholders' equity		
Common stock:		
Authorized — 960,000,000 shares of $0.10 par value in 2016 and 2015, respectively		
Issued — 475,042,692 shares and 423,768,593 shares in 2016 and 2015, respectively	47,504	42,377
Additional paid-in capital	1,727,310	721,997
Retained earnings	1,098,703	1,552,014
Accumulated other comprehensive income (loss)	985	(365)
Less treasury stock, at cost:		
9,892,680 shares in 2016 and 2015, respectively	(306,835)	(306,835)
Total stockholders' equity	2,567,667	2,009,188
	$5,122,569	$5,253,038

The accompanying notes are an integral part of these consolidated financial statements.

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
(In thousands, except per share amounts)	2016	2015	2014
OPERATING REVENUES			
Natural gas	$1,022,590	$1,025,044	$1,590,625
Crude oil and condensate	151,106	248,211	313,889
Gain (loss) on derivative instruments	(38,950)	56,686	219,319
Brokered natural gas	13,569	16,383	34,416
Other	7,362	10,826	14,762
	1,155,677	1,357,150	2,173,011
OPERATING EXPENSES			
Direct operations	100,696	140,814	145,529
Transportation and gathering	436,542	427,588	349,321
Brokered natural gas	10,785	12,592	30,030
Taxes other than income	29,223	42,809	47,012
Exploration	27,662	27,460	28,746
Depreciation, depletion and amortization	590,128	622,211	632,760
Impairment of oil and gas properties and other assets	435,619	114,875	771,037
General and administrative	87,242	69,444	82,590
	1,717,897	1,457,793	2,087,025
Earnings (loss) on equity method investments	(2,477)	6,415	3,080
Gain (loss) on sale of assets	(1,857)	3,866	17,120
INCOME (LOSS) FROM OPERATIONS	(566,554)	(90,362)	106,186
Loss on debt extinguishment	4,709	—	—
Interest expense	88,336	96,911	73,785
Income (loss) before income taxes	(659,599)	(187,273)	32,401
Income tax benefit	(242,475)	(73,382)	(72,067)
NET INCOME (LOSS)	$(417,124)	$(113,891)	$104,468
Earnings (loss) per share			
Basic	$(0.91)	$(0.28)	$0.25
Diluted	$(0.91)	$(0.28)	$0.25
Weighted-average common shares outstanding			
Basic	456,847	413,696	415,840
Diluted	456,847	413,696	417,601
Dividends per common share	$0.08	$0.08	$0.08

The accompanying notes are an integral part of these consolidated financial statements.

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Net income (loss)	$(417,124)	$(113,891)	$104,468
Other comprehensive income, net of taxes:			
Reclassification adjustment for settled cash flow hedge contracts(1)	—	—	86,726
Changes in fair value of cash flow hedge contracts(2)	—	—	(80,175)
Postretirement benefits:			
Net gain (loss)(3)	1,794	1,786	(325)
Prior service cost (4)	(514)	—	—
Amortization of prior service cost (5)	70	—	—
Amortization of net (gain) loss(6)	—	—	(16)
Total other comprehensive income	1,350	1,786	6,210
Comprehensive income (loss)	$(415,774)	$(112,105)	$110,678

(1) Net of income taxes of $(57,477) for the year ended December 31, 2014.
(2) Net of income taxes of $53,135 for the year ended December 31, 2014.
(3) Net of income taxes of $(1,052), $(1,043) and $48 for the year ended December 31, 2016, 2015 and 2014, respectively.
(4) Net of income taxes of $301 for the year ended December 31, 2016.
(5) Net of income taxes of $(41) for the year ended December 31, 2016.
(6) Net of income taxes of $10 for the year ended December 31, 2014.

The accompanying notes are an integral part of these consolidated financial statements.

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
(In thousands)	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$(417,124)	$(113,891)	$104,468
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	590,128	622,211	632,760
Impairment of oil and gas properties and other assets	435,619	114,875	771,037
Deferred income tax benefit	(230,707)	(72,968)	(112,567)
(Gain) loss on sale of assets	1,857	(3,866)	(17,120)
Exploratory dry hole cost	10,120	3,452	7,907
(Gain) loss on derivative instruments	38,950	(56,686)	(219,319)
Net cash received (paid) in settlement of derivative instruments	(1,682)	194,289	81,716
(Earnings) loss on equity method investments	2,477	(6,415)	(3,080)
Amortization of debt issuance costs	5,083	4,454	4,754
Stock-based compensation and other	25,982	13,645	21,429
Changes in assets and liabilities:			
Accounts receivable, net	(71,060)	112,406	(11,689)
Income taxes	(5,975)	(711)	(34,282)
Inventories	3,044	(3,023)	3,441
Other current assets	(21)	(817)	733
Accounts payable and accrued liabilities	5,794	(64,078)	(7,583)
Interest payable	(2,573)	(455)	10,466
Other assets and liabilities	2,465	(1,685)	1,989
Stock-based compensation tax benefit	—	—	1,375
Net cash provided by operating activities	392,377	740,737	1,236,435
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(375,153)	(955,602)	(1,479,632)
Acquisitions	—	(16,312)	(214,737)
Proceeds from sale of assets	50,419	7,653	39,492
Restricted cash	—	—	28,094
Investment in equity method investments	(28,484)	(29,073)	(38,057)
Net cash used in investing activities	(353,218)	(993,334)	(1,664,840)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from debt	90,000	877,000	2,032,000
Repayments of debt	(587,000)	(604,000)	(1,427,000)
Treasury stock repurchases	—	—	(138,852)
Sale of common stock, net	995,279	—	—
Dividends paid	(36,187)	(33,090)	(33,278)
Stock-based compensation tax benefit	—	—	(1,375)
Capitalized debt issuance costs	(3,223)	(7,838)	(5,626)
Other	—	85	90
Net cash provided by financing activities	458,869	232,157	425,959
Net increase (decrease) in cash and cash equivalents	498,028	(20,440)	(2,446)
Cash and cash equivalents, beginning of period	514	20,954	23,400
Cash and cash equivalents, end of period	$498,542	$514	$20,954

The accompanying notes are an integral part of these consolidated financial statements.

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CABOT OIL & GAS CORPORATION
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands, except per share amounts)	Common Shares	Common Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance at December 31, 2013	422,015	$42,201	5,618	$(167,983)	$710,940	$ (8,361)	$1,627,805	$2,204,602
Net income	—	—	—	—	—	—	104,468	104,468
Stock amortization and vesting	900	91	—	—	867	—	—	958
Stock-based compensation	—	—	—	—	(1,375)	—	—	(1,375)
Purchase of treasury stock	—	—	4,275	(138,852)	—	—	—	(138,852)
Cash dividends at $0.08 per share	—	—	—	—	—	—	(33,278)	(33,278)
Other comprehensive income (loss)	—	—	—	—	—	6,210	—	6,210
Balance at December 31, 2014	422,915	$42,292	9,893	$(306,835)	$710,432	$ (2,151)	$1,698,995	$2,142,733
Net loss	—	—	—	—	—	—	(113,891)	(113,891)
Exercise of stock appreciation rights	40	4	—	—	(946)	—	—	(942)
Stock amortization and vesting	814	81	—	—	12,511	—	—	12,592
Cash dividends at $0.08 per share	—	—	—	—	—	—	(33,090)	(33,090)
Other comprehensive income (loss)	—	—	—	—	—	1,786	—	1,786
Balance at December 31, 2015	423,769	$42,377	9,893	$(306,835)	$721,997	$ (365)	$1,552,014	$2,009,188
Net loss	—	—	—	—	—	—	(417,124)	(417,124)
Issuance of common stock	50,600	5,060	—	—	990,229	—	—	995,289
Exercise of stock appreciation rights	28	3	—	—	(201)	—	—	(198)
Stock amortization and vesting	646	64	—	—	16,867	—	—	16,931
Sale of stock held in rabbi trust	—	—	—	—	544	—	—	544
Stock-based compensation	—	—	—	—	(2,126)	—	—	(2,126)
Cash dividends at $0.08 per share	—	—	—	—	—	—	(36,187)	(36,187)
Other comprehensive income (loss)	—	—	—	—	—	1,350	—	1,350

Balance at December 31, 2016	475,043	$47,504	9,893	$(306,835)	$1,727,310	$ 985	$1,098,703	$2,567,667

The accompanying notes are an integral part of these consolidated financial statements.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Nature of Operations

Cabot Oil & Gas Corporation and its subsidiaries (the Company) are engaged in the development, exploitation, exploration, production and marketing of natural gas, oil and, to a lesser extent, NGLs exclusively within the continental United States. The Company also transports, stores, gathers and purchases natural gas for resale. The Company's exploration and development activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs.

The Company operates in one segment, natural gas and oil development, exploitation and exploration. The Company's oil and gas properties are managed as a whole rather than through discrete operating segments or business units. Operational information is tracked by geographic area; however, financial performance is assessed as a single enterprise and not on a geographic basis. Allocation of resources is made on a project basis across the Company's entire portfolio without regard to geographic areas.

The consolidated financial statements include the accounts of the Company and its subsidiaries after eliminating all significant intercompany balances and transactions. Certain reclassifications have been made to prior year statements to conform with current year presentation. These reclassifications have no impact on previously reported stockholders' equity, net income (loss) or cash flows.

Significant Accounting Policies

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with a maturity of three months or less and deposits in money market funds that are readily convertible to cash to be cash equivalents. Cash and cash equivalents were primarily concentrated in two financial institutions at December 31, 2016. The Company periodically assesses the financial condition of its financial institutions and considers any possible credit risk to be minimal.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company determines to be uncollectible based on the specific identification method.

Inventories

Inventories are comprised of natural gas in storage, tubular goods and well equipment and pipeline imbalances. Natural gas in storage and tubular goods and well equipment balances are carried at average cost.

Natural gas gathering and pipeline operations normally include imbalance arrangements with the pipeline. The volumes of natural gas due to or from the Company under imbalance arrangements are recorded at actual selling or purchase prices, as the case may be, and are adjusted monthly to market prices.

Equity Method Investments

The Company accounts for its investments in entities over which the Company has significant influence, but not control, using the equity method of accounting. Under the equity method of accounting, the Company increases its investment for contributions made and records its proportionate share of net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. The Company records the activity for its equity method investments on a one month lag. In addition, the Company evaluates its equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other-than-temporary decline in the value of the investment.

Properties and Equipment

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole drilling costs, are expensed.

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Development costs, including the costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

Exploratory drilling costs are capitalized when incurred pending the determination of whether a well has found proved reserves. The determination is based on a process which relies on interpretations of available geologic, geophysical, and engineering data. If a well is determined to be successful, the capitalized drilling costs will be reclassified as part of the cost of the well. If a well is determined to be unsuccessful, the capitalized drilling costs will be charged to exploration expense in the Consolidated Statement of Operations in the period the determination is made. If an exploratory well requires a major capital expenditure before production can begin, the cost of drilling the exploratory well will continue to be carried as an asset pending determination of whether reserves have been found only as long as: (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and (ii) drilling of an additional exploratory well is under way or firmly planned for the near future. If drilling in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well is assumed to be impaired and its costs are charged to exploration expense.

Development costs of proved oil and gas properties, including estimated dismantlement, restoration and abandonment costs and acquisition costs, are depreciated and depleted on a field basis by the units-of-production method using proved developed and proved reserves, respectively. Properties related to gathering and pipeline systems and equipment are depreciated using the straight-line method based on estimated useful lives ranging from 10 to 25 years. Generally pipeline and transmission systems are depreciated over 12 to 25 years, gathering and compression equipment is depreciated over 10 years and storage equipment and facilities are depreciated over 10 to 16 years. Buildings are depreciated on a straight-line basis over 25 to 40 years. Certain other assets are depreciated on a straight-line basis over 3 to 10 years.

Costs of sold or abandoned properties that make up a part of an amortization base (partial field) remain in the amortization base if the units-of-production rate is not significantly affected. If significant, a gain or loss, if any, is recognized and the sold or abandoned properties are retired. A gain or loss, if any, is also recognized when a group of proved properties (entire field) that make up the amortization base has been retired, abandoned or sold.

The Company evaluates its proved oil and gas properties for impairment whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. The Company compares expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on estimates of future natural gas and crude oil prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and oil.

Unproved oil and gas properties are assessed periodically for impairment on an aggregate basis through periodic updates to the Company's undeveloped acreage amortization based on past drilling and exploration experience, the Company's expectation of converting leases to held by production and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. During 2016, 2015 and 2014, amortization associated with the Company's unproved properties was $25.0 million, $41.4 million and $17.4 million, respectively, and is included in depreciation, depletion, and amortization in the Consolidated Statement of Operations.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. The asset retirement costs are depreciated using the units-of-production method. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities are also recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2016, there were no assets legally restricted for purposes of settling asset retirement obligations.

Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Accretion expense is included in depreciation, depletion and amortization expense in the Consolidated Statement of Operations.

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Derivative Instruments and Hedging Activities

The Company enters into derivative contracts, primarily swaps, collars and basis swaps, to manage its exposure to price fluctuations on a portion of its anticipated future natural gas and oil production. The Company's credit agreement restricts the ability of the Company to enter into commodity derivatives other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company's risk management policies and where such derivatives do not subject the Company to material speculative risks. All of the Company's derivatives are used for risk management purposes and are not held for trading purposes.

All derivatives are recognized on the balance sheet and are measured at fair value. At the end of each quarterly period, these derivatives are marked-to-market. If the derivative does not qualify or is not designated as a cash flow hedge, changes in the fair value of the derivative are recognized in income. If the derivative qualifies and is designated as a cash flow hedge, changes in the fair value of the derivative are deferred in accumulated other comprehensive income to the extent the hedge is effective.

For derivatives that qualify and are designated as a cash flow hedges, the hedging relationship between the hedging instruments and hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively if and when a hedging instrument becomes ineffective. Gains and losses deferred in accumulated other comprehensive income related to cash flow hedges that become ineffective remain unchanged until the related production occurs. If the Company determines that it is probable that a forecasted hedged transaction will not occur, deferred gains or losses on the related hedging instrument are recognized in income immediately.

Gains and losses on derivatives designated as cash flow hedges are included in natural gas and crude oil and condensate revenues. Gains and losses on derivatives which represent hedge ineffectiveness and gains and losses on derivatives not designated or that do not qualify for hedge accounting are included in operating revenues in gain (loss) on derivative instruments. The resulting cash flows are reported as cash flows from operating activities.

Fair Value of Assets and Liabilities

The Company follows the authoritative accounting guidance for measuring fair value of assets and liabilities in its financial statements. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company is able to classify fair value balances based on the observability of these inputs. The authoritative guidance for fair value measurements establishes three levels of the fair value hierarchy, defined as follows:

- Level 1: Unadjusted, quoted prices for identical assets or liabilities in active markets.
- Level 2: Quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Significant, unobservable inputs for use when little or no market data exists, requiring a significant degree of judgment.

The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. Depending on the particular asset or liability, input availability can vary depending on factors such as product type, longevity of a product in the market and other particular transaction conditions. In some cases, certain inputs used to measure fair value may be categorized into different levels of the fair value hierarchy. For disclosure purposes under the accounting guidance, the lowest level that contains significant inputs used in the valuation should be chosen.

Revenue Recognition

Natural gas and oil sales result from interests in oil and gas properties owned by the Company. Sales of natural gas and oil are recognized when the product is delivered and title transfers to the purchaser. Payment is generally received one to three months after the sale has occurred.

Producer Gas Imbalances. The Company applies the sales method of accounting for natural gas revenue. Under this method, revenues are recognized based on the actual volume of natural gas sold to purchasers. Natural gas production operations may include joint owners who take more or less than the production volumes entitled to them on certain properties. Production volume is monitored to minimize these natural gas imbalances. Under this method, a natural gas imbalance liability is recorded if the Company's excess takes of natural gas exceed its estimated remaining proved developed reserves for these properties at the actual price realized upon the gas sale. A receivable is recognized only to the extent an imbalance cannot be recouped from the reserves in the underlying properties. The Company’s aggregate imbalance positions at December 31, 2016 and 2015 were not material.

Brokered Natural Gas. Revenues and expenses related to brokering natural gas are reported gross as part of operating revenues and operating expenses in accordance with applicable accounting standards. The Company buys and sells natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby the Company and/or the counterparty takes title to the natural gas purchased or sold.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

The Company recognizes accrued interest related to uncertain tax positions in interest expense and accrued penalties related to such positions in general and administrative expense in the Consolidated Statement of Operations.

Stock-Based Compensation

The Company accounts for stock-based compensation under the fair value method of accounting. Under this method, compensation cost is measured at the grant date for equity-classified awards and remeasured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is generally the vesting period. To calculate fair value, the Company uses either a Monte Carlo or Black-Scholes valuation model depending on the specific provisions of the award. Stock-based compensation cost for all types of awards is included in general and administrative expense in the Consolidated Statement of Operations.

The tax benefit for stock-based compensation is included as both a cash outflow from operating activities and a cash inflow from financing activities in the Consolidated Statement of Cash Flows. The Company recognizes a tax benefit only to the extent it reduces the Company's income taxes payable.

Environmental Matters

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. Any insurance recoveries are recorded as assets when received.

Credit and Concentration Risk

Substantially all of the Company's accounts receivable result from the sale of natural gas and oil and joint interest billings to third parties in the oil and gas industry. This concentration of purchasers and joint interest owners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. The Company does not anticipate any material impact on its financial results due to non-performance by the third parties.

During the years ended December 31, 2016, 2015 and 2014, two customers accounted for approximately 19% and 10%, two customers accounted for approximately 16% and 14% and two customers accounted for approximately 14% and 10%, respectively, of the Company's total sales. The Company does not believe that the loss of any of these customers would have a material adverse effect because alternative customers are readily available.

Use of Estimates

In preparing financial statements, the Company follows accounting principles generally accepted in the United States. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas and oil reserves and related cash flow estimates which are used to compute depreciation, depletion and amortization and impairments of proved oil and gas properties. Other significant estimates include natural gas and oil revenues and expenses, fair value of derivative instruments, estimates of expenses related to legal, environmental and other contingencies, asset retirement obligations, postretirement obligations, stock-based compensation and deferred income taxes. Actual results could differ from those estimates.

Recently Adopted Accounting Pronouncements

Debt Issuance Costs. In March 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. The amendments in this update require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. In August 2015, the FASB issued ASU No. 2015-15, Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements. The update provides authoritative guidance for debt issuance costs related to line-of-credit arrangements, noting the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The guidance is effective for interim and annual periods beginning after December 15, 2015.

Effective January 1, 2016, the Company adopted ASU No. 2015-03 as a change in accounting principle. The Consolidated Balance Sheet as of December 31, 2015 has been retrospectively adjusted to reflect the adoption of this guidance, resulting in a decrease of $8.9 million in both other assets and long-term debt related to the debt issuance costs on the Company's senior notes. There was no impact to the Company's Consolidated Statement of Operations or Statement of Cash Flows.

Going Concern. In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern. This guidance requires management to evaluate, for each reporting period, whether there are conditions and events that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the financial statements are issued. Management will have to make certain disclosures if it concludes that substantial doubt exists or when its plans alleviate substantial doubt about the entity’s ability to continue as a going concern. This guidance is effective for annual reporting periods ending after December 15, 2016, and for annual periods and interim periods thereafter, with earlier adoption permitted. Effective December 31, 2016, the Company adopted ASU No. 2014-15. The adoption of this guidance did not have an impact on the Company's Consolidated Financial Statements or Notes to the Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

Financial Instruments. In January 2016, the FASB issued ASU 2016-01, Financial Instruments - Overall, as an amendment to Accounting Standards Codification (ASC) Subtopic 825-10. The amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Among other items, this update will simplify the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. When a qualitative assessment indicates that impairment exists, an entity is required to measure the investment at fair value. This impairment assessment reduces the complexity of the other-than-temporary impairment guidance that entities follow currently. The guidance is effective for annual periods beginning after December 15, 2018, including interim periods within those annual periods. Early adoption of this amendment is not permitted. The adoption of this guidance will change the methodology that the Company uses to evaluate its equity method investments for impairment. The Company is currently evaluating the

effect that adopting this guidance will have on its financial position, results of operation or cash flows.
Stock-Based Compensation. In March 2016, the FASB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting, as an amendment to ASC Topic 718. The areas for simplification in this update involve several aspects of the accounting for share-based payment transactions, including the income tax consequences, forfeitures,

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classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance is effective for interim and annual periods beginning after December 15, 2016. Early adoption is permitted. An entity that elects early adoption must adopt all of the amendments in the same period. Amendments related to the timing of when excess tax benefits are recognized, minimum statutory withholding requirements, forfeitures, and intrinsic value should be applied using a modified retrospective transition method by means of a cumulative-effect adjustment to equity as of the beginning of the period in which the guidance is adopted. Amendments related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement should be applied retrospectively. Amendments requiring recognition of excess tax benefits and tax deficiencies in the income statement and the practical expedient for estimating expected term should be applied prospectively. An entity may elect to apply the amendments related to the presentation of excess tax benefits on the statement of cash flows using either a prospective transition method or a retrospective transition method.

The Company adopted this guidance effective January 1, 2017. The recognition of previously unrecognized windfall tax benefits resulted in a cumulative-effect adjustment of $42.2 million, which increased retained earnings and decreased net deferred tax liabilities by the same amount as of the beginning of 2017. Effective January 1, 2017, cash paid by the Company when directly withholding shares from employee awards for tax-withholding purposes will be classified as a financing activity. This change will be recognized retrospectively beginning January 1, 2017. The effect of this change resulted in an increase in net cash provided by operating activities of $5.1 million and $8.9 million for the years ended December 31, 2016 and 2015, respectively. In addition, net cash provided by financing activities decreased by $5.1 million and $8.9 million for the years ended December 31, 2016 and 2015, respectively. The remaining provisions of this amendment will not have a material effect on the Company's financial position or results of operations.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases, as a new Topic, ASC Topic 842. The new lease guidance supersedes Topic 840. The core principle of the guidance is that a company should recognize the assets and liabilities that arise from leases. This ASU does not apply to leases to explore for or use minerals, oil, natural gas and similar nonregenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. The guidance is effective for interim and annual periods beginning after December 15, 2018. This ASU can be adopted using a modified retrospective approach. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, results of operations or cash flows.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, as a new Topic, ASC Topic 606. The new revenue recognition standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606), which deferred the effective date of ASU No. 2014-09 by one year, making the new standard effective for interim and annual periods beginning after December 15, 2017. This ASU can be adopted either retrospectively or as a cumulative-effect adjustment as of the date of adoption.

Additionally, in March 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus agent considerations (reporting revenue gross versus net), which clarifies the implementation guidance on principal versus agent considerations on such matters. In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying performance obligations and licensing, which clarifies guidance related to identifying performance obligations and licensing implementation guidance contained in the new revenue recognition standard. In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-scope improvements and practical expedients, which addresses narrow-scope improvements to the guidance on collectibility, non-cash consideration, and completed contracts at transition. Additionally, the amendments in this update provide a practical expedient for contract modifications at transition and an accounting policy election related to the presentation of sales taxes and other similar taxes collected from customers. In December 2016, the FASB issued ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers, which clarifies the guidance or corrects unintended application of guidance. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, results of operations or cash flows.

Statement of Cash Flows. In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The guidance addresses eight specific cash flow issues for which current GAAP is either unclear or does not include specific guidance. The guidance is effective for annual periods beginning after December 15, 2017 and interim periods within those annual periods. Early adoption is permitted, provided that all of the amendments are adopted in the same period. This ASU must be adopted using a retrospective transition method. The Company is currently evaluating the effect that adopting this guidance will have on its presentation of cash flows. Adopting the guidance is expected to have no effect on the Company's financial position or results of operations.

Accounting Changes and Error Corrections. In January 2017, the FASB issued ASU No. 2017-03, Accounting Changes and Error Corrections (Topic 250) and Investments - Equity Method and Joint Venture (Topic 323), which states that registrants should consider additional qualitative disclosures if the impact of an issued but not yet adopted ASU is unknown or cannot be reasonably estimated and to include a description of the effect of the accounting policies that the registrant expects to apply, if determined. Transition guidance in certain issued but not yet adopted ASUs, including Leases and Revenue Recognition, was also updated to reflect this amendment. This guidance is effective immediately.

2. Acquisitions and Divestitures

Acquisitions

In December 2014, the Company completed the acquisition of certain proved and unproved oil and gas properties in the Eagle Ford Shale in south Texas for $30.5 million. Total net cash consideration paid by the Company was $29.9 million, which reflects the impact of customary purchase price adjustments and acquisition costs.

In October 2014, the Company completed the acquisition of certain proved and unproved oil and gas properties in the Eagle Ford Shale in south Texas. Total net cash consideration paid by the Company was $185.2 million, which reflects the purchase price of $210.0 million, adjusted by $17.4 million for properties that the seller was unable to obtain consents for certain leaseholds prior to closing and $7.4 million for the impact of customary purchase price adjustments and acquisition costs. In addition, the Company also assumed a liability of $1.2 million related to asset retirement obligations of the wells acquired. In April 2015, the Company completed the acquisition of the remaining oil and gas properties for which the seller was unable to obtain consents at closing for $16.0 million.

The Company accounted for these transactions as an asset purchase, whereby the identifiable assets acquired were recorded at cost, with the respective assigned carrying amount based on the relative fair value of the unproved and proved properties at the acquisition date. The fair value measurement of assets acquired was based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and gas properties were measured using discounted future cash flows. The discount factor used was based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and oil. Significant inputs to the valuation of oil and gas properties include (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates based on the Company's experience with similar properties in which it operates; (iii) estimated future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate of 10.0%.

Divestitures

The Company recognized an aggregate net gain (loss) on sale of assets of $(1.9) million, $3.9 million and $17.1 million for the years ended December 31, 2016, 2015 and 2014, respectively.

In February 2016, the Company completed the divestiture of certain proved and unproved oil and gas properties in east Texas for $56.4 million and recognized a $0.5 million gain on sale of assets. The purchase price included a $6.3 million deposit that was received in the fourth quarter of 2015.

In October 2014, the Company completed the divestiture of certain proved and unproved oil and gas properties in east Texas to a third party for $44.3 million and recognized a $19.9 million gain on sale of assets.

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3. Properties and Equipment, Net

Properties and equipment, net are comprised of the following:

	December 31,	
(In thousands)	2016	2015
Proved oil and gas properties	$7,437,604	$8,821,146
Unproved oil and gas properties	260,543	390,434
Gathering and pipeline systems	187,846	243,672
Land, building and other equipment	84,462	117,848
	7,970,455	9,573,100
Accumulated depreciation, depletion and amortization	(3,720,330)	(4,596,221)
	$4,250,125	$4,976,879

Impairment

In December 2016, the Company recorded an impairment of $435.6 million associated with oil and gas properties and related pipeline assets located in West Virginia and Virginia. The impairment of these properties and the related pipeline assets was due to the carrying value of these assets exceeding the expected undiscounted cash flows of the underlying assets. These assets were reduced to fair value of approximately $89.2 million.

In December 2015, the Company recorded an impairment of $114.9 million associated with oil and gas properties in certain non-core fields in south Texas, east Texas and Louisiana. The impairment of these fields was due to a significant decline in commodity prices in late 2015. These fields were reduced to fair value of approximately $89.9 million using discounted future cash flows.

In December 2014, the Company recorded a $771.0 million impairment of oil and gas properties in certain non-core fields, primarily in east Texas. The impairment of these fields was due to a significant decline in commodity prices in late 2014 and management's decision not to pursue any further activity in these non-core areas in the current price environment. These fields were reduced to fair value of approximately $86.5 million using discounted future cash flows.

The fair value of the impaired properties was based on significant inputs that were not observable in the market and are considered to be Level 3 inputs as defined by ASC 820. Refer to Note 1 for a description of fair value hierarchy. Key assumptions included (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates based on the Company's experience with similar properties in which it operates; (iii) estimated future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate of 10%.

Capitalized Exploratory Well Costs

The following table reflects the net changes in capitalized exploratory well costs:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Balance at beginning of period	$—	$10,557	$—
Additions to capitalized exploratory well costs pending the determination of proved reserves	—		10,557
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	—	(10,557)	—
Capitalized exploratory well costs charged to expense	—	—	—
Balance at end of period	$—	$—	$10,557

As of December 31, 2014, capitalized exploratory well costs of $10.6 million had been capitalized for a period of one year or less. There were no capitalized exploratory well costs as of December 31, 2016 and 2015.

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4. Equity Method Investments

The Company has two equity method investments, Constitution Pipeline Company, LLC (Constitution) and Meade Pipeline Co LLC (Meade), which are further described below. Activity related to these equity method investments is as follows:

	Constitution			Meade			Total		
	Year Ended December 31,			Year Ended December 31,			Year Ended December 31,		
(In thousands)	2016	2015	2014	2016	2015	2014	2016	2015	2014
Balance at beginning of period	$90,345	$64,268	$26,892	$13,172	$3,761	$—	$103,517	$68,029	$26,892
Contributions	8,975	19,625	34,200	19,509	9,448	3,857	28,484	29,073	38,057
Earnings (loss) on equity method investments	(2,470)	6,452	3,176	(7)	(37)	(96)	(2,477)	6,415	3,080
Balance at end of period	$96,850	$90,345	$64,268	$32,674	$13,172	$3,761	$129,524	$103,517	$68,029

Constitution Pipeline Company, LLC

In April 2012, the Company acquired a 25% equity interest in Constitution, which was formed to develop, construct and operate a 124-mile large diameter pipeline to transport natural gas from northeast Pennsylvania to both the New England and New York markets. Under the terms of the agreement, the Company agreed to invest its proportionate share of costs associated with the development and construction of the pipeline and related facilities, subject to a contribution cap of $250 million.

On April 22, 2016, Constitution announced that the New York State Department of Environmental Conservation (NYSDEC) denied Constitution's application for a Section 401 Water Quality Certification (Certification) for the New York State portion of its proposed 124-mile route. During the second quarter of 2016, Constitution filed legal actions in the U.S Court of Appeals for the Second Circuit and the U.S District Court for the Northern District of New York challenging the legality and appropriateness of the NYSDEC’s decision. Both courts have granted Constitution's motions to expedite the schedules for the legal actions.

Constitution stated that it remains committed to pursuing the project and that it intends to pursue all available options to challenge the NYSDEC’s decision. In light of the denial of the Certification and ongoing litigation, Constitution has revised its target in-service date to the second half of 2018, assuming that the challenge process is satisfactorily and promptly concluded.

In light of the NYSDEC’s denial and resulting litigation, the Company evaluated its investment in Constitution for other-than-temporary impairment (OTTI) and as of December 31, 2016, does not believe there is an indication of an OTTI. The Company’s evaluation considered various factors, including but not limited to prior Federal Energy Regulatory Commission (FERC) approval and the related economic viability of the project, legal actions filed by Constitution and the expected duration of the legal proceedings, which are at very early stages, and the other members’ commitment to the project. To the extent that the legal and regulatory proceedings have unfavorable outcomes, or if Constitution concludes that the project is no longer viable or elects to not go forward as legal and regulatory actions progress, the Company will reevaluate the facts and circumstances relative to its conclusions with respect to OTTI. In the event that facts and circumstances change, the Company may be required to recognize an impairment charge up to its investment value at such time, net of any cash and working capital held by Constitution. The Company will continue to monitor the carrying value of its investment as required.

At this time, the Company remains committed to funding the project in an amount in proportion to its ownership interest for the development and construction of the new pipeline. The Company's total contributions for this project are expected to be approximately $240.0 million. As of December 31, 2016, the Company has made contributions of $88.5 million since inception of the project and expects to contribute approximately $148.9 million over the next three years.

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Meade Pipeline Co LLC

In February 2014, the Company acquired a 20% equity interest in Meade, which was formed to participate in the development and construction of a 177-mile pipeline (Central Penn Line) that will transport natural gas from Susquehanna County, Pennsylvania to an interconnect with Transcontinental Gas Pipe Line Company, LLC’s (Transco) mainline in Lancaster County, Pennsylvania. The new pipeline will be constructed and operated by Transco and will be owned by Transco and Meade in proportion to their respective ownership percentages of approximately 61% and 39%, respectively. Under the terms of the Meade LLC agreement, the Company agreed to invest its proportionate share of Meade’s anticipated costs associated with the new pipeline. The Company expects to contribute approximately $120.3 million over the next three years. The in-service date for the new pipeline is expected to be mid-2018; however, this estimate is contingent on the timely issuance of remaining outstanding permits.

5. Debt and Credit Agreements

The Company's debt and credit agreements consisted of the following:

	December 31,	
(In thousands)	2016	2015
7.33% weighted-average senior notes (1)	$—	$20,000
6.51% weighted-average senior notes	361,000	425,000
9.78% senior notes	67,000	67,000
5.58% weighted-average senior notes	175,000	175,000
3.65% weighted-average senior notes	925,000	925,000
Revolving credit facility	—	413,000
	$1,528,000	$2,025,000
Unamortized debt issuance costs	(7,470)	(8,861)
	$1,520,530	$2,016,139

(1) Includes $20.0 million of current portion of long-term debt at December 31, 2015.

The Company has debt maturities of $304.0 million due in 2018, $87.0 million due in 2020 and $188.0 million due in 2021. In addition, the revolving credit facility matures in 2020. No other tranches of debt are due within the next five years.

At December 31, 2016, the Company was in compliance with all restrictive financial covenants, as amended, for both its revolving credit facility and senior notes.

Senior Notes

The Company has various issuances of senior notes. Interest on each of the senior notes is payable semi-annually. Under the terms of the various senior note agreements, the Company may prepay all or any portion of the notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium.

Effective December 31, 2015, the Company amended the agreements governing its senior notes to adjust certain financial covenants and to include an additional financial covenant, as further described below. The amended agreements provide that the asset coverage ratio (present value of proved reserves to debt, as defined in the agreements) be calculated based on the present value of proved reserves before income taxes, whereas prior to these amendments, the present value was calculated after income taxes. The minimum asset coverage ratio was also reduced from 1.75 to 1.0 to 1.25 to 1.0 through and including December 31, 2017 and increases back to a ratio of 1.75 to 1.0 beginning on January 1, 2018 and thereafter. The amendments also introduce a leverage ratio covenant, which is defined in the agreement as the ratio of debt to consolidated EBITDAX. The leverage ratio may not exceed a maximum ratio of:

- 4.75 to 1.0 through and including December 31, 2016;
- 4.25 to 1.0 through and including December 31, 2017; and

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3.50 to 1.0 beginning on March 31, 2018 and remains in effect until the Company maintains a leverage ratio below 3.0 to 1.0 for two consecutive fiscal quarters ending on or after December 31, 2017, or receives an investment grade rating by Standard & Poor's Ratings Services (S&P) or Moody’s Investor Service, Inc (Moody's).

In addition, the amendments provide for potential increases to the original coupon rates ranging from 0 to 125 basis points depending on the asset coverage and leverage ratios at the end of the respective quarterly period, as defined in the note agreements. These potential increases lapse when the Company maintains a leverage ratio between 3.0 to 1.0 for two consecutive fiscal quarters ending on or after December 31, 2017 or receives an investment grade rating by S&P or Moody's. As of December 31, 2016 and 2015, there were no interest rate adjustments required for the Company's senior notes.

The note agreements continue to include a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of 2.8 to 1.0, which was unchanged by the amendments. There are also various other covenants and events of default customarily found in such debt instruments.

In conjunction with the execution of the amendments, the Company incurred approximately $1.9 million of debt issuance costs, which were capitalized and are being amortized over the term of the respective amended agreements.

7.33% Weighted-Average Senior Notes

In July 2001, the Company issued $170.0 million of senior unsecured notes to a group of seven institutional investors in a private placement. The notes had bullet maturities and were issued in three separate tranches.

As of December 31, 2016, the Company has repaid all of the $170.0 million of aggregate maturities associated with the 7.33% weighted-average senior notes.

6.51% Weighted-Average Senior Notes

In July 2008, the Company issued $425.0 million of senior unsecured notes to a group of 41 institutional investors in a private placement. The notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$245,000,000	10 years	July 2018	6.44 %
Tranche 2	$100,000,000	12 years	July 2020	6.54 %
Tranche 3	$80,000,000	15 years	July 2023	6.69 %

In May 2016, the Company repurchased $8.0 million of Tranche 1, $13.0 million of Tranche 2 and $43.0 million of Tranche 3 for a total of $64.0 million for $68.3 million. The Company recognized a $4.7 million extinguishment loss associated with the premium paid and the write-off of a portion of the related deferred financing costs due to early repayment.

9.78% Senior Notes

In December 2008, the Company issued $67.0 million aggregate principal amount of 10 year 9.78% senior unsecured notes to a group of four institutional investors in a private placement.

5.58% Weighted-Average Senior Notes

In December 2010, the Company issued $175.0 million of senior unsecured notes to a group of eight institutional investors in a private placement. The notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$88,000,000	10 years	January 2021	5.42 %
Tranche 2	$25,000,000	12 years	January 2023	5.59 %
Tranche 3	$62,000,000	15 years	January 2026	5.80 %

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3.65% Weighted Average Senior Notes

In September 2014, the Company issued $925.0 million of senior unsecured notes to a group of 24 institutional investors in a private placement. The notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$100,000,000	7 years	September 2021	3.24 %
Tranche 2	$575,000,000	10 years	September 2024	3.67 %
Tranche 3	$250,000,000	12 years	September 2026	3.77 %

In conjunction with the issuance of the 3.65% weighted average senior notes in September 2014, the Company incurred approximately $5.6 million of debt issuance costs, which were capitalized and are being amortized over the term of the notes. The amortization of debt issuance costs is included in interest expense in the Consolidated Statement of Operations.

Revolving Credit Agreement

The Company's revolving credit facility is unsecured. The borrowing base is redetermined annually under the terms of the revolving credit facility on April 1. In addition, either the Company or the banks may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Effective April 19, 2016, the Company’s borrowing base was reduced from $3.4 billion to $3.2 billion. The maximum credit amount under the revolving credit facility remained unchanged at $1.8 billion; however, the available commitments were reduced to $1.6 billion at the time of the redetermination. As a result of the repurchase of the Company's 6.51% weighted-average senior notes in the second quarter of 2016, the available commitments under the revolving credit facility were increased to $1.7 billion and remained at that level as of December 31, 2016. The Company revolving credit facility matures in April 2020.

Effective December 31, 2015, the Company amended its revolving credit facility to adjust certain financial covenants and include an additional financial covenant, as further described below. The amendment provided that the asset coverage ratio (present value of proved reserves to debt, as defined in the agreement) be calculated based on the present value of proved reserves before income taxes, whereas prior to the amendment, the present value was calculated after income taxes. The minimum asset coverage ratio was also reduced from 1.75 to 1.0 to 1.25 to 1.0 through and including December 31, 2017 and increases back to a ratio of 1.75 to 1.0 beginning on March 31, 2018. The amendment also introduced a leverage ratio covenant, which is defined in the agreement as the ratio of debt to consolidated EBITDAX. The ratio may not exceed a maximum ratio of:

- 4.75 to 1.0 through and including December 31, 2016;
- 4.25 to 1.0 through and including December 31, 2017; and
- 3.50 to 1.0 beginning on March 31, 2018 and remains in effect until the Company maintains a leverage ratio below 3.0 to 1.0 for two consecutive fiscal quarters beginning on or after December 31, 2017, or receives an investment grade rating by S&P or Moody’s.

In addition to the amendment to the asset coverage ratio and inclusion of the leverage ratio covenant, the amended revolving credit facility also increased the maximum leverage ratio and associated margins. Interest rates under the amended revolving credit facility are based on LIBOR or ABR indications, plus a margin which ranges from 50 to 300 basis points, as defined in the agreement. These rates will remain in effect (i) until the first date occurring on or after December 31, 2017 on which both the asset coverage ratio is greater than 1.75 to 1.0 and the leverage ratio is less than 3.0 to 1.0 for two consecutive fiscal quarters, at which time the related margins will revert back to pre-amendment levels of 50 to 225 basis points, or (ii) upon the Company achieving an investment grade rating from either Moody's or S&P, at which time the associated margins will be adjusted and determined based on the Company's credit rating on a prospective basis.

The revolving credit facility also contains various other customary covenants that remained unchanged as a result of the amendment, which include the following (with all calculations based on definitions contained in the agreement):

(a) Maintenance of a minimum annual coverage ratio of consolidated cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

(b) Maintenance of a minimum current ratio of 1.0 to 1.0.

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The revolving credit facility also provides for a commitment fee on the unused available balance at annual rates ranging from 0.30% to 0.50%. The other terms and conditions of the amended facility are generally consistent with the terms and conditions of the revolving credit facility prior to its amendment.

The Company incurred approximately $7.8 million and $1.1 million of debt issuance costs in connection with the April 17, 2015 and December 31, 2015 amendments to the revolving credit facility, respectively, which were capitalized and will be amortized over the term of the amended credit facility. The remaining unamortized costs will be amortized over the term of the amended revolving credit facility.

At December 31, 2016, the Company had no borrowings outstanding under its revolving credit facility and had unused commitments of $1.7 billion. The Company's weighted-average effective interest rates for the revolving credit facility during the years ended December 31, 2016, 2015 and 2014 were approximately 2.3%, 2.2% and 2.2%, respectively.

6. Derivative Instruments and Hedging Activities

Through March 31, 2014, the Company elected to designate its commodity derivatives as cash flow hedges for accounting purposes. Effective April 1, 2014, the Company discontinued hedge accounting for its commodity derivatives on a prospective basis. As a result of discontinuing hedge accounting, the unrealized loss included in accumulated other comprehensive income (loss) as of April 1, 2014 of $73.4 million ($44.2 million net of tax) was frozen and reclassified into natural gas and crude oil and condensate revenues in the Statement of Operations throughout 2014 as the underlying hedged transactions occurred. As of December 31, 2014, there are no gains or losses deferred in accumulated other comprehensive income (loss) associated with the Company’s commodity derivatives.

As of December 31, 2016, the Company had the following outstanding commodity derivatives instruments:

				Collars					
				Floor		Ceiling		Swaps	Basis Swaps
Type of Contract	Volume		Contract Period	Range	Weighted-Average	Range	Weighted-Average	Weighted-Average	Weighted-Average
Natural gas	35.5	Bcf	Jan. 2017 - Dec. 2017					$ 3.12	
Natural gas	16.2	Bcf	Feb. 2017 - Dec. 2017					$ 3.46	
Natural gas	35.5	Bcf	Jan. 2017 - Dec. 2017	$—	$ 3.09	$3.42-$3.45	$ 3.43		
Natural gas	21.3	Bcf	Jan. 2018 - Dec. 2019						$ 0.42
Crude oil	1.8	Mmbbl	Jan. 2017 - Dec. 2017	$—	$ 50.00	$56.25-$56.50	$ 56.39		

In the table above, natural gas prices are stated per Mcf and crude oil prices are stated per barrel.

Effect of Derivative Instruments on the Consolidated Balance Sheet

		Fair Values of Derivative Instruments			
		Derivative Assets		Derivative Liabilities	
		December 31,		December 31,	
(In thousands)	Balance Sheet Location	2016	2015	2016	2015
Commodity contracts	Other assets (non-current)	$2,991	$ —	$ —	$ —
Commodity contracts	Derivative instruments (current)	—	—	40,259	—
		$2,991	$ —	$ 40,259	$ —

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Offsetting of Derivative Assets and Liabilities in the Consolidated Balance Sheet

	December 31,	
(In thousands)	2016	2015
Derivative assets		
Gross amounts of recognized assets	$ 2,991	$ —
Gross amounts offset in the statement of financial position	—	—
Net amounts of assets presented in the statement of financial position	2,991	—
Gross amounts of financial instruments not offset in the statement of financial position	—	—
Net amount	$ 2,991	$ —
Derivative liabilities		
Gross amounts of recognized liabilities	$ 40,259	$ —
Gross amounts offset in the statement of financial position	—	—
Net amounts of liabilities presented in the statement of financial position	40,259	—
Gross amounts of financial instruments not offset in the statement of financial position	757	—
Net amount	$ 41,016	$ —

Effect of Derivative Instruments on Accumulated Other Comprehensive Income (Loss)

The effective portion of gain (loss) recognized in accumulated other comprehensive income (loss) on derivatives is as follows:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Commodity contracts	$ —	$ —	$ (133,310)

The effective portion of gain (loss) reclassified from accumulated other comprehensive income (loss) into income is as follows:

	Year Ended December 31,		
(In thousands)	2016	2015	2014[(1)]
Natural gas revenues	$ —	$ —	$ (143,577)
Crude oil and condensate revenues	—	—	(626)
	$ —	$ —	$ (144,203)

(1) The Company ceased hedge accounting effective April 1, 2014. As a result, a loss of approximately $73.4 million related to amounts previously frozen in accumulated other comprehensive income (loss) was reclassified into income during 2014.

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Effect of Derivative Instruments on the Consolidated Statement of Operations

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Derivatives Designated as Hedges			
Cash received (paid) on settlement of derivative instruments			
Natural gas	$—	$—	$(70,557)
Crude oil and condensate	—	—	(218)
	$—	$—	$(70,775)
Derivatives Not Designated as Hedges			
Cash received (paid) on settlement of derivative instruments			
Natural gas[(1)]	$—	$—	$(73,020)
Crude oil and condensate[(1)]	—	—	(408)
Gain (loss) on derivative instruments	(1,682)	194,289	81,716
Non-cash gain (loss) on derivative instruments			
Gain (loss) on derivative instruments	(37,268)	(137,603)	137,603
	$(38,950)	$56,686	$145,891
	$(38,950)	$56,686	$75,116

(1) Relates entirely to the reclassification from accumulated other comprehensive income (loss) of previously frozen losses associated with derivatives that were de-designated as cash flow hedges on April 1, 2014.

There was no ineffectiveness recorded in the Company’s Consolidated Statement of Operations related to its derivative instruments designated as cash flow hedges for the year ended December 31, 2014.

Additional Disclosures about Derivative Instruments and Hedging Activities

The use of derivative instruments involves the risk that the counterparties will be unable to meet their obligations under the agreements. The Company's counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and its derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty. The Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable.

Certain counterparties to the Company's derivative instruments are also lenders under its revolving credit facility. The Company's revolving credit facility and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of its derivative liabilities in certain situations. The Company also has netting arrangements with each of its counterparties that allow it to offset assets and liabilities from separate derivative contracts with that counterparty.

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7. Fair Value Measurements

Financial Assets and Liabilities

The following fair value hierarchy table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2016
Assets				
Deferred compensation plan	$ 12,587	$ —	$ —	$ 12,587
Derivative instruments	—	—	2,991	2,991
Total assets	$ 12,587	$ —	$ 2,991	$ 15,578
Liabilities				
Deferred compensation plan	$ 24,169	$ —	$ —	$ 24,169
Derivative instruments	—	21,400	18,859	40,259
Total liabilities	$ 24,169	$ 21,400	$ 18,859	$ 64,428

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2015
Assets				
Deferred compensation plan	$ 12,921	$ —	$ —	$ 12,921
Total assets	$ 12,921	$ —	$ —	$ 12,921
Liabilities				
Deferred compensation plan	$ 22,371	$ —	$ —	$ 22,371
Total liabilities	$ 22,371	$ —	$ —	$ 22,371

The Company's investments associated with its deferred compensation plan consist of mutual funds and deferred shares of the Company's common stock that are publicly traded and for which market prices are readily available.
The derivative instruments were measured based on quotes from the Company's counterparties. Such quotes have been derived using an income approach that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, basis differentials, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. Estimates are verified using relevant NYMEX futures contracts and/or are compared to multiple quotes obtained from counterparties for reasonableness. The determination of the fair values presented above also incorporates a credit adjustment for non-performance risk. The Company measured the non-performance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions with which it has derivative transactions while non-performance risk of the Company is evaluated using a market credit spread provided by the Company's bank. The Company has not incurred any losses related to non-performance risk of its counterparties and does not anticipate any material impact on its financial results due to non-performance by third parties.

The most significant unobservable inputs relative to the Company's Level 3 derivative contracts are basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties' valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

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The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Balance at beginning of period	$—	$85,958	$(3,910)
Total gains (losses) (realized or unrealized):			
Included in earnings	(17,886)	32,864	35,067
Included in other comprehensive income	—	—	3,755
Settlements	2,018	(118,822)	51,046
Transfers in and/or out of level 3	—	—	—
Balance at end of period	$(15,868)	$—	$85,958
Change in unrealized gains (losses) relating to assets and liabilities still held at the end of the period	$(15,868)	$—	$85,958

There were no transfers between Level 1 and Level 2 fair value measurements for the years ended December 31, 2016, 2015 and 2014.

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments and acquisitions of oil and gas properties and other assets, at fair value on a nonrecurring basis. During the year ended December 31, 2014, the Company acquired certain oil and gas properties that were allocated based on the relative fair value of the proved and unproved properties. The Company also recorded an impairment charge related to certain oil and gas properties and other assets during the years ended December 31, 2016, 2015 and 2014. Refer to Note 2 for additional disclosures related to the non-recurring fair value measurements associated with these acquisitions and Note 3 for additional disclosures related to fair value associated with the impaired assets. As none of the Company’s other non-financial assets and liabilities were measured at fair value as of December 31, 2016, 2015 and 2014, additional disclosures were not required.

The estimated fair value of the Company's asset retirement obligation at inception is determined by utilizing the income approach by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the measurement of the asset retirement obligations was classified as Level 3 in the fair value hierarchy.

Fair Value of Other Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amount reported in the Consolidated Balance Sheet for cash and cash equivalents approximate fair value due to the short-term maturities of these instruments. Cash and cash equivalents are classified as Level 1 in the fair value hierarchy and the remaining financial instruments are classified as Level 2.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's senior notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all senior notes and the revolving credit facility is based on interest rates currently available to the Company. The Company's debt is valued using an income approach and classified as Level 3 in the fair value hierarchy.

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The carrying amount and fair value of debt is as follows:

(In thousands)	December 31, 2016 Carrying Amount	December 31, 2016 Estimated Fair Value	December 31, 2015 Carrying Amount	December 31, 2015 Estimated Fair Value
Long-term debt	$1,520,530	$1,463,643	$2,016,139	$1,839,530
Current maturities	—	—	(20,000)	(20,378)
Long-term debt, excluding current maturities	$1,520,530	$1,463,643	$1,996,139	$1,819,152

8. Asset Retirement Obligations

Activity related to the Company's asset retirement obligations is as follows:

(In thousands)	Year Ended December 31, 2016
Balance at beginning of period	$145,606
Liabilities incurred	3,522
Liabilities settled	(1,148)
Liabilities divested	(24,338)
Accretion expense	8,065
Change in estimate	2,026
Balance at end of period	$133,733

As of December 31, 2016 and 2015, $2.0 million is included in accrued liabilities in the Consolidated Balance Sheet, which represents the current portion of the Company’s asset retirement obligation.

9. Commitments and Contingencies

Transportation and Gathering Agreements

The Company has entered into certain natural gas and oil transportation and gathering agreements with various pipeline carriers. Under certain of these agreements, the Company is obligated to ship minimum daily quantities, or pay for any deficiencies at a specified rate. The Company's forecasted production to be shipped on these pipelines is expected to exceed minimum daily quantities provided in the agreements. The Company is also obligated under certain of these arrangements to pay a demand charge for firm capacity rights on pipeline systems regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability.

As of December 31, 2016, the Company's future minimum obligations under transportation and gathering agreements are as follows:

(In thousands)	
2017	$148,061
2018	167,749
2019	155,904
2020	150,522
2021	150,110
Thereafter	1,071,827
	$1,844,173

Drilling Rig Commitments

As of December 31, 2016, the Company has a remaining commitment for one drilling rig for its capital program in the Marcellus Shale, expiring in December 2017, with an initial term of three years. As of December 31, 2016, the future minimum commitment under this agreement is $4.2 million in 2017.

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Hydraulic Fracturing Services Commitments

During the year ended December 31, 2016, the Company entered into a fifteen month agreement, which ends in December 2017, for hydraulic fracturing services in the Marcellus Shale. As of December 31, 2016, the future minimum commitment under this agreement is $4.0 million in 2017.

Lease Commitments

The Company leases certain office space, warehouse facilities, vehicles, machinery and equipment under cancelable and non-cancelable leases. Rent expense under these arrangements totaled $10.7 million, $13.9 million and $10.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2016 are as follows:

(In thousands)	
2017	$7,244
2018	6,727
2019	6,363
2020	5,889
2021	4,783
Thereafter	6,203
	$37,209

Legal Matters

The Company is a defendant in various legal proceedings arising in the normal course of business. All known liabilities are accrued when management determines they are probable based on its best estimate of the potential loss. While the outcome and impact of these legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material effect on the Company's financial position, results of operations or cash flows.

Contingency Reserves

When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional losses with respect to those matters in which reserves have been established. The Company believes that any such amount above the amounts accrued would not be material to the Consolidated Financial Statements. Future changes in facts and circumstances not currently foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

10. Income Taxes

Income tax benefit is summarized as follows:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Current			
Federal	$(9,920)	$983	$44,887
State	(1,848)	(1,397)	(4,387)
	(11,768)	(414)	40,500
Deferred			
Federal	(218,357)	(72,869)	(32,375)
State	(12,350)	(99)	(80,192)
	(230,707)	(72,968)	(112,567)
Income tax benefit	$(242,475)	$(73,382)	$(72,067)

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Income tax benefit was different than the amounts computed by applying the statutory federal income tax rate as follows:

	Year Ended December 31,					
	2016		2015		2014	
(In thousands, except rates)	Amount	Rate	Amount	Rate	Amount	Rate
Computed "expected" federal income tax	$(230,860)	35.00 %	$(65,546)	35.00 %	$11,341	35.00 %
State income tax, net of federal income tax benefit	(10,888)	1.65 %	(3,152)	1.68 %	903	2.79 %
Deferred tax adjustment related to change in overall state tax rate	(663)	0.10 %	2,822	(1.51)%	(86,956)	(268.36)%
Valuation allowance	221	(0.03)%	187	(0.10)%	3,977	12.27 %
Uncertain tax positions	—	— %	—	— %	(1,974)	(6.09)%
Provision to return adjustments	(121)	0.02 %	(6,326)	3.38 %	(791)	(2.44)%
Other, net	(164)	0.02 %	(1,367)	0.73 %	1,433	4.42 %
Income tax benefit	$(242,475)	36.76 %	$(73,382)	39.18 %	$(72,067)	(222.41)%

In 2016, the Company's overall effective tax rate decreased compared to 2015, primarily due to larger provision-to-return adjustments in 2015 compared to 2016. The overall effective tax rate was significantly lower in 2014 due to a change in the effective state income tax rate based on updated state apportionment factors in the states in which the Company operates. For state income tax purposes, the Company must estimate the respective amounts of future earnings that are subject to income tax in the various states in which the Company operates. These estimates may change based on a variety of factors, including, but not limited to, the composition and location of the Company’s asset base, its employees, and its customers. The 2014 decrease in the Company’s state apportionment factors was primarily driven by a shift in the sourcing of revenues based on the location of customers to whom the Company ultimately sells its natural gas in the northeast United States. The 2014 decrease in the effective state income tax rate significantly affected the Company’s estimated net state deferred tax liabilities reflected in its Consolidated Balance Sheet, resulting in an income tax benefit of approximately $87.0 million that was reflected in the Company’s provision for income taxes in 2014.

The composition of net deferred tax liabilities is as follows:

	December 31,	
(In thousands)	2016	2015
Deferred Tax Assets		
Net operating losses	$352,001	$223,402
Alternative minimum tax credits	218,773	228,693
Foreign tax credits	3,816	3,837
Derivative instruments	13,771	—
Incentive compensation	22,852	22,509
Deferred compensation	8,217	7,869
Post-retirement benefits	13,865	13,556
Other	2,743	2,905
Less: valuation allowance	(5,186)	(4,965)
Total	630,852	497,806
Deferred Tax Liabilities		
Properties and equipment	1,207,545	1,303,840
Equity method investments	2,754	1,202
Total	1,210,299	1,305,042
Net deferred tax liabilities	$579,447	$807,236

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As of December 31, 2016, the Company had alternative minimum tax credit carryforwards of $218.8 million, which do not expire and can be used to offset regular income taxes in future years to the extent that regular income taxes exceed the alternative minimum tax in any such year. The Company also had gross net operating loss carryforwards of $1.0 billion and $636.1 million for federal and state reporting purposes, respectively, the majority of which will expire between 2022 and 2036. The Company has $4.8 million of state valuation allowances, and believes it is more likely than not that the remainder of the deferred tax benefits will be utilized prior to their expiration. Tax benefits related to employee stock-based compensation included in net operating loss carryforwards but not reflected in deferred tax assets as of December 31, 2016 are approximately $120.3 million.

Unrecognized Tax Benefits

A reconciliation of unrecognized tax benefits is as follows:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Balance at beginning of year	$663	$663	$3,700
Additions based on tax provisions related to the current year	—	—	—
Additions for tax positions of prior years	—	—	—
Reductions for tax positions of prior years	—	—	(3,037)
Settlements	—	—	—
Balance at end of year	$663	$663	$663

During 2013, the Company recorded unrecognized tax benefits of $3.7 million based on the allocation of certain gains associated with its divestitures for purposes of computing state income taxes. These benefits were reduced during 2014 by $3.0 million based on changes to the Company's state tax rates. There was no change to the Company's unrecognized tax benefits during 2016 or 2015. If recognized, the net tax benefit of $0.7 million would not have a material effect on the Company's effective tax rate.

The Company files income tax returns in the U.S. federal, various states and other jurisdictions. The Company is no longer subject to examinations by state authorities before 2012 or by federal authorities before 2013. The Company is not currently under examination by the Internal Revenue Service. The Company believes that appropriate provisions have been made for all jurisdictions and all open years, and that any assessment on these filings will not have a material impact on the Company's financial position, results of operations or cash flows.

11. Employee Benefit Plans

Postretirement Benefits

The Company provides certain health care benefits for retired employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. The health care plans are contributory, with participants' contributions adjusted annually. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. During the year ended December 31, 2016, the Company expanded their eligibility definition to include those employees who have reached the age of 50 with at least 20 years of service. The Company was providing postretirement benefits to 310 retirees and their dependents at the end of 2016 and 276 retirees and their dependents at the end of 2015.

Obligations and Funded Status

The funded status represents the difference between the accumulated benefit obligation of the Company's postretirement plan and the fair value of plan assets at December 31. The postretirement plan does not have any plan assets; therefore, the unfunded status is equal to the amount of the December 31 accumulated benefit obligation.

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The change in the Company's postretirement benefit obligation is as follows:

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Change in Benefit Obligation			
Benefit obligation at beginning of year	$36,626	$37,076	$34,995
Service cost	2,323	1,808	1,295
Interest cost	1,498	1,448	1,343
Actuarial (gain) loss	(2,846)	(2,829)	373
Benefits paid	(934)	(877)	(930)
Plan amendments	815	—	—
Benefit obligation at end of year	$37,482	$36,626	$37,076
Change in Plan Assets			
Fair value of plan assets at end of year	—	—	—
Funded status at end of year	$(37,482)	$(36,626)	$(37,076)

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet consist of the following:

	December 31,		
(In thousands)	2016	2015	2014
Current liabilities	$1,223	$1,333	$1,249
Long-term liabilities	36,259	35,293	35,827
	$37,482	$36,626	$37,076

Amounts Recognized in Accumulated Other Comprehensive Income (Loss)

Amounts recognized in accumulated other comprehensive income (loss) consist of the following:

	December 31,		
(In thousands)	2016	2015	2014
Net actuarial (gain) loss	$(2,266)	$580	$3,408
Prior service cost	704	—	—
	$(1,562)	$580	$3,408

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Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income (Loss)

	Year Ended December 31,		
(In thousands)	2016	2015	2014
Components of Net Periodic Postretirement Benefit Cost			
Service cost	$2,323	$1,808	$1,295
Interest cost	1,498	1,448	1,343
Amortization of prior service cost	111	—	—
Amortization of net loss	—	—	(26)
Net periodic postretirement cost	$3,932	$3,256	$2,612
Other Changes in Benefit Obligations Recognized in Other Comprehensive Income (Loss)			
Net (gain) loss	$(2,846)	$(2,829)	$373
Prior service cost	815	—	—
Amortization of prior service cost	(111)	—	—
Amortization of net loss	—	—	26
Total recognized in other comprehensive income	(2,142)	(2,829)	399
Total recognized in net periodic benefit cost and other comprehensive income (loss)	$1,790	$427	$3,011

Assumptions

Assumptions used to determine projected postretirement benefit obligations and postretirement costs are as follows:

	December 31,		
	2016	2015	2014
Discount rate(1)	4.30 %	4.25 %	4.00 %
Health care cost trend rate for medical benefits assumed for next year (pre-65)	7.50 %	5.50 %	6.00 %
Health care cost trend rate for medical benefits assumed for next year (post-65)	5.00 %	5.50 %	6.00 %
Ultimate trend rate (pre-65)	4.50 %	4.50 %	4.50 %
Ultimate trend rate (post-65)	4.50 %	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate (pre-65)	2023	2018	2018
Year that the rate reaches the ultimate trend rate (post-65)	2018	2018	2018

(1) Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2016, 2015 and 2014, respectively, the beginning of year discount rates of 4.25%, 4.00% and 4.75% were used.

Coverage provided to participants age 65 and older is under a fully-insured arrangement. The Company subsidy is limited to 60% of the expected annual fully-insured premium for participants age 65 and older. For all participants under age 65, the Company subsidy for all retiree medical and prescription drug benefits, beginning January 1, 2006, was limited to an aggregate annual amount not to exceed $648,000. This limit increases by 3.5% annually thereafter.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In thousands)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost	$ 968	$ (721)
Effect on postretirement benefit obligation	6,828	(5,338)

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Cash Flows

Contributions. The Company expects to contribute approximately $1.2 million to the postretirement benefit plan in 2017.

Estimated Future Benefit Payments. The following estimated benefit payments under the Company's postretirement plans, which reflect expected future service, are expected to be paid as follows:

(In thousands)	
2017	1,249
2018	1,344
2019	1,488
2020	1,625
2021	1,708
Years 2022 - 2026	10,489

Savings Investment Plan

The Company has a Savings Investment Plan (SIP), which is a defined contribution plan. The Company matches a portion of employees' contributions in cash. Participation in the SIP is voluntary and all regular employees of the Company are eligible to participate. The Company matches employee contributions dollar-for-dollar, up to the maximum IRS limit, on the first six percent of an employee's pretax earnings. The SIP also provides for discretionary profit sharing contributions in an amount equal to nine percent of an eligible plan participant's salary and bonus. During the years ended December 31, 2016, 2015 and 2014, the Company made contributions of $6.5 million, $7.1 million and $7.2 million, respectively, which are included in general and administrative expense in the Consolidated Statement of Operations. The Company's common stock is an investment option within the SIP.

Deferred Compensation Plan

The Company has a deferred compensation plan which is available to officers and certain members of the Company's management group and acts as a supplement to the SIP. The Internal Revenue Code does not cap the amount of compensation that may be taken into account for purposes of determining contributions to the deferred compensation plan and does not impose limitations on the amount of contributions to the deferred compensation plan. At the present time, the Company anticipates making a contribution to the deferred compensation plan on behalf of a participant in the event that Internal Revenue Code limitations cause a participant to receive less than the Company matching contribution under the SIP.

The assets of the deferred compensation plan are held in a rabbi trust and are subject to additional risk of loss in the event of bankruptcy or insolvency of the Company.

Under the deferred compensation plan, the participants direct the deemed investment of amounts credited to their accounts. The trust assets are invested in either mutual funds that cover the investment spectrum from equity to money market, or may include holdings of the Company's common stock, which is funded by the issuance of shares to the trust. The mutual funds are publicly traded and have market prices that are readily available. The Company's common stock is not currently an investment option in the deferred compensation plan. Shares of the Company's stock currently held in the deferred compensation plan represent vested performance share awards that were previously deferred into the rabbi trust. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments. The market value of the trust assets, excluding the Company's common stock, was $12.6 million and $12.9 million at December 31, 2016 and 2015, respectively, and is included in other assets in the Consolidated Balance Sheet. Related liabilities, including the Company's common stock, totaled $24.2 million and $22.4 million at December 31, 2016 and 2015, respectively, and are included in other liabilities in the Consolidated Balance Sheet. With the exception of the Company's common stock, there is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets because the changes in market value of the trust assets are offset completely by changes in the value of the liability, which represents trust assets belonging to plan participants.

As of December 31, 2016 and 2015, 495,774 shares and 534,174 shares of the Company's common stock were held in the rabbi trust, respectively. These shares were recorded at the market value on the date of deferral, which totaled $5.1 million and $5.7 million at December 31, 2016 and 2015, respectively, and is included in additional paid-in capital in stockholders' equity in the Consolidated Balance Sheet. The Company recognized compensation expense (benefit) of $1.8 million, $(6.4) million and $(4.9) million in 2016, 2015 and 2014, respectively, which is included in general and administrative expense in the

Consolidated Statement of Operations representing the increase (decrease) in the closing price of the Company's shares held in the trust. The Company's common stock issued to the trust is not considered outstanding for purposes of calculating basic earnings per share, but is considered a common stock equivalent in the calculation of diluted earnings per share.

The Company made contributions to the deferred compensation plan of $0.6 million, $1.0 million and $0.8 million in 2016, 2015 and 2014, respectively, which are included in general and administrative expense in the Consolidated Statement of Operations.

12. Capital Stock

Common Stock Issuance

On February 22, 2016, the Company entered into an underwriting agreement, pursuant to which the Company sold an aggregate of 44.0 million shares of common stock at a price to the Company of $19.675 per share. On February 26, 2016, the Company received $865.7 million in net proceeds, after deducting underwriting discounts and commissions. On March 2, 2016, the Company sold an additional 6.6 million shares of common stock as a result of the exercise of the underwriters' option to purchase additional shares and received $129.9 million in net proceeds. These net proceeds were used for general corporate purposes, including repaying indebtedness under the Company's revolving credit facility and repurchasing certain of the Company's senior notes.

Incentive Plans

On May 1, 2014, the Company's shareholders approved the 2014 Incentive Plan, which replaced the 2004 Incentive Plan that expired on April 29, 2014. Under the 2014 Incentive Plan, incentive and non-statutory stock options, stock appreciation rights (SARs), stock awards, cash awards and performance awards may be granted to key employees, consultants and officers of the Company. Non-employee directors of the Company may be granted discretionary awards under the 2014 Incentive Plan consisting of stock options or stock awards. A total of 18.0 million shares of common stock may be issued under the 2014 Incentive Plan. Under the 2014 Incentive Plan, no more than 10.0 million shares may be issued pursuant to incentive stock options. No additional awards may be granted under the 2014 Incentive Plan on or after May 1, 2024. At December 31, 2016, approximately 16.0 million shares are available for issuance under the 2014 Incentive Plan.

No additional awards will be granted under any of the Company's prior plans, including the 2004 Incentive Plan. Awards outstanding under the 2004 Incentive Plan will remain outstanding in accordance with their original terms and conditions.

Treasury Stock

In August 1998, the Board of Directors authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. The timing and amount of these stock purchases are determined at the discretion of management. The Company may use the repurchased shares to fund stock compensation programs presently in existence, or for other corporate purposes. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase shares of the Company.

During 2016 and 2015, there were no share repurchases. During the year ended December 31, 2014, the Company repurchased 4.3 million shares for a total cost of $138.9 million. Since the authorization date, the Company has repurchased 29.9 million shares of the 40.0 million total shares authorized, of which 20.0 million shares have been retired, for a total cost of approximately $388.4 million. No treasury shares have been delivered or sold by the Company subsequent to the repurchase. As of December 31, 2016, 9.9 million shares were held as treasury stock.

Dividend Restrictions

The Board of Directors of the Company determines the amount of future cash dividends, if any, to be declared and paid on the common stock depending on, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures, and its future business prospects. None of the senior note or credit agreements in place have restricted payment provisions or other provisions limiting dividends.

13. Stock-Based Compensation

General

Stock-based compensation expense for the years ended December 31, 2016, 2015 and 2014 was $26.0 million, $13.7 million and $21.5 million, respectively, and is included in general and administrative expense in the Consolidated Statement of Operations.

For the year ended December 31, 2016 and 2014, the Company realized $2.1 million and $1.4 million, respectively, of tax expense related to the book compensation cost in excess of the federal tax deduction for employee stock-based compensation. There was no tax expense or benefit recognized from stock-based compensation during the year ended December 31, 2015. The Company is able to recognize tax benefits only to the extent they reduce the Company's income taxes payable. All shortfalls must be recognized in the period in which they arise.

Restricted Stock Awards

Restricted stock awards are granted from time to time to employees of the Company. The fair value of restricted stock grants under the 2014 Incentive Plan is based on the closing stock price on the grant date. Restricted stock awards generally vest either at the end of a three year service period or on a graded or graduated vesting basis at each anniversary date over a three or four year service period.

For awards that vest at the end of the service period, expense is recognized ratably using a straight-line approach over the service period. Under the graded or graduated approach, the Company recognizes compensation cost ratably over the requisite service period, as applicable, for each separately vesting tranche as though the awards are, in substance, multiple awards. For all restricted stock awards, vesting is dependent upon the employees' continued service with the Company, with the exception of employment termination due to death, disability or retirement. The Company accelerates the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company's stock-based compensation programs.

The Company used an annual forfeiture rate assumption ranging from 5.0% to 6.0% for purposes of recognizing stock-based compensation expense for restricted stock awards. The annual forfeiture rates were based on the Company's actual forfeiture history for this type of award to various employee groups.

The following table is a summary of restricted stock award activity:

	Year Ended December 31,					
	2016		2015		2014	
	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	49,825	$ 33.76	49,869	$ 33.40	27,806	$ 20.53
Granted	—	—	5,900	25.44	47,500	34.76
Vested	(6,650)	33.02	(5,944)	22.55	(17,437)	15.84
Forfeited	—	—	—	—	(8,000)	35.00
Outstanding at end of period[(1)(2)]	43,175	$ 33.87	49,825	$ 33.76	49,869	$ 33.40

(1) As of December 31, 2016, the aggregate intrinsic value was $1.0 million and was calculated by multiplying the closing market price of the Company's stock on December 31, 2016 by the number of non-vested restricted stock awards outstanding.

(2) As of December 31, 2016, the weighted average remaining contractual term of non-vested restricted stock awards outstanding was 0.3 years.

Compensation expense recorded for all restricted stock awards for the years ended December 31, 2016, 2015 and 2014 was $0.4 million, $0.4 million and $1.0 million, respectively. Unamortized expense as of December 31, 2016 for all outstanding restricted stock awards was $0.1 million and will be recognized over the next year.

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The total fair value of restricted stock awards that vested during 2016, 2015 and 2014 was $0.2 million, $0.2 million and $0.6 million, respectively.

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. The fair value of the restricted stock units under the 2014 Incentive Plan is based on the closing stock price on the grant date. These units vest immediately and compensation expense is recorded immediately. Restricted stock units are issued when the director ceases to be a director of the Company.

The following table is a summary of restricted stock unit activity:

	Year Ended December 31,					
	2016		2015		2014	
	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share	Shares	Weighted-Average Grant Date Fair Value per Share
Outstanding at beginning of period	425,438	$ 13.81	604,214	$ 12.48		