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Eclipse Resources Corp
Form 10-K
March 02, 2018

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, 2017

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF
1934

For the transition period from _____ to _____

Commission File Number: 001-36511

Eclipse Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	46-4812998
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2121 Old Gatesburg Rd, Suite 110	
State College, PA	16803
(Address of principal executive offices)	(Zip code)

(814) 308-9754

(Registrant's telephone number, including area code)

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

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

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

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

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

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

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

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

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

Large accelerated filer ☐

Accelerated filer ☐

Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2017, the last business day of the most recently completed second fiscal quarter, was approximately \$248 million.

Number of shares of the registrant's common stock outstanding at March 2, 2018: 301,770,671 shares.

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Documents incorporated by reference: Portions of the registrant's proxy statement for its 2018 annual meeting of stockholders to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end are incorporated by reference into Part III of this Annual Report on Form 10-K.

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Cautionary Statement Regarding Forward-Looking Statements

This Annual Report on Form 10-K (the “Annual Report”) contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and income or losses, projected costs and capital expenditures, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words “will,” “plan,” “would,” “could,” “endeavor,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are or were, when made, based on current expectations and assumptions about future events and are or were, when made based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described in “Item 1A. Risk Factors” of this Annual Report.

Forward-looking statements may include statements about, among other things:

- realized prices for natural gas, natural gas liquids (“NGLs”) and oil and the volatility of those prices;
- write-downs of our natural gas and oil asset values due to declines in commodity prices;
- our business strategy;
- our reserves;
- general economic conditions;
- our financial strategy, liquidity and capital required for developing our properties and the timing related thereto;
- the timing and amount of our future production of natural gas, NGLs and oil;
- our hedging strategy and results;
- future drilling plans;
- competition and government regulations, including those related to hydraulic fracturing;
- the anticipated benefits under our commercial agreements;
 - marketing of natural gas, NGLs and oil;
- leasehold and business acquisitions and joint ventures;
- leasehold terms expiring before production can be established and our costs to extend such terms;
- the costs, terms and availability of gathering, processing, fractionation and other midstream services;
- credit markets;
- uncertainty regarding our future operating results, including initial production rates and liquids yields in our type curve areas; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil. These risks include, but are not limited to, legal and environmental risks, drilling and other operating risks, regulatory changes, commodity price volatility and the significant decline of the price of natural gas, NGLs and oil from historical highs, inflation, lack of availability of drilling, production and processing equipment and services, counterparty credit risk, the uncertainty inherent in estimating natural gas, NGLs and oil reserves and in projecting future rates of production, cash flows and access to capital, risks associated with our level of indebtedness, the timing of development expenditures, and the other risks described in “Item 1A. Risk Factors” of this Annual Report.

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

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

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

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect new information obtained or events or circumstances that occur after the date of this Annual Report.

Glossary of Oil and Natural Gas Terms

As used in this Annual Report, unless the context indicates or otherwise requires, the following terms have the following meanings:

- “Bbl” refers to a standard barrel containing 42 U.S. gallons;
- “Bbls/d” refers to Bbls per day;
- “Bcfe” refers to one billion cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids;
- “Boe” refers to one barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil;
- “Btu” refers to one British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit;
- “Completion” refers to the process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency;
- “Condensate” or “Condensate Window” refers to the area in which we generally expect Utica Shale wells to produce natural gas having a heat content greater than 1,210 Btu, with an initial condensate yield of approximately 60 to 300 barrels per MMcf of natural gas produced;
- “Developed acreage” refers to the number of acres that are allocated or assignable to productive wells or wells capable of production;
- “Differential” refers to an adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas;
- “Dry Gas” refers to the area in which we generally expect Utica Shale wells to produce natural gas having a heat content between 1,010 Btu and 1,150 Btu with no initial condensate yield;
- “Dth” refers to a thermal unit, and is equal to one million Btus;
 - “Dry hole” or “dry well” refers to a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes;

- “Exploration” refers to a development or other project that may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects;
- “Field” refers to an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations;
- “Formation” refers to a layer of rock that has distinct characteristics that differs from nearby rock;
- “Gross acres” or “gross wells” refers to the total acres or wells, as the case may be, in which a working interest is owned;
- “Horizontal drilling” refers to a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval;
- “Identified drilling locations” refers to total gross (net) resource play locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors;
- “Marcellus Condensate” or “Marcellus Area” refers to the area in which we generally expect Marcellus Shale wells to produce a natural gas having a heat content of approximately 1,300 Btu, with an initial condensate yield of approximately 60-140 barrels per MMcf of natural gas produced;
- “MBbl” refers to one thousand barrels;
- “MBoe” refers to one thousand Boe;
- “Mcf” refers to one thousand cubic feet;
- “Mcf/e” refers to one thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs;
- “Mcf/d” refers to Mcfs per day;
- “MMBbls” refers to one million barrels;
- “MMBoe” refers to one million Boe;
- “MMBtu” refers to one million British thermal units;
- “MMcf” refers to one million cubic feet;
- “MMcf/e” refers to one million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs;
- “Net acres” refers to the amount of leased real estate that a petroleum and/or natural gas company has a true working interest in. Net acres express actual percentage interest when a company shares its working interest with another company; the total acreage under lease by a company is referred to as gross acres. Net acres account for the Company’s percentage interest, multiplied by the gross acreage. If a company holds the entire working interest, its net acreage and gross acreage will be the same;
- “Net production” refers to production that is owned by us less royalties and production due others;
- “NGLs” refers to natural gas liquids, which are hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline;
- “NYMEX” refers to the New York Mercantile Exchange;
- “Operator” refers to the individual or company responsible for the exploration and/or production of an oil or natural gas well or lease;
- “Plugging” refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface;

- “Productive well” refers to a well that is expected to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceeds production expenses and taxes;
- “Prospect” refers to a geological feature mapped as a location or probable location of a commercial oil and/ or gas accumulation. A prospect is defined as a result of geophysical and geological studies allowing the identification and quantification of uncertainties, probabilities of success, estimates of potential resources and economic viability;
- “Proved undeveloped reserves” refers to proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion;
- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances;
- (ii) 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;
- (iii) 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 (as defined in Rule 4-10(a) (2) of Regulation S-X), or by other evidence using reliable technology establishing reasonable certainty;
- “PV-10” refers to, when used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using sales prices used in estimating proved oil and gas reserves and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC;
- “Realized price” refers to the cash market price less all expected quality, transportation and demand adjustments;
- “Reservoir” refers to a porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs;
- “Rich Gas” or “Rich Gas Window” refers to the area in which we generally expect Utica Shale wells to produce natural gas having a heat content between 1,150 Btu and 1,210 Btu, with an initial condensate yield of approximately 0 to 60 barrels per MMcf of natural gas produced;
- “SEC” refers to the United States Securities and Exchange Commission;
- “Spacing” refers to the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies;
- “Spot market price” refers to the cash market price without reduction for expected quality, transportation and demand adjustments;
- “Standardized measure” refers to discounted future net cash flows estimated by applying sales prices used in estimating proved oil and gas reserves to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate;

•“Undeveloped acreage” refers to lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves;

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

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

•“WTI” refers to West Texas Intermediate; and

•The terms “development project,” “development well,” “exploratory well,” “proved developed reserves,” “proved reserves” and “reserves” are defined by the SEC.

Items 1 and 2. Business and Properties

Our Company

We are an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin. As of December 31, 2017, we had assembled an acreage position approximating 203,000 net acres in Eastern Ohio. We intend to focus on developing our substantial inventory of horizontal drilling locations during commodity price environments that will allow us to generate attractive returns and will continue to opportunistically add to this acreage position where we can acquire acreage at attractive prices. As used in this Annual Report, unless the context indicates or otherwise requires, “Eclipse,” “Eclipse Resources,” the “Company,” “we,” “our,” “us” and like terms refer collectively to Eclipse Resources Corporation and its consolidated subsidiaries.

Our Properties

As of December 31, 2017, we had approximately 96,000 net acres in the Utica Shale fairway, which we refer to as the Utica Core Area and approximately 15,500 acres in our Marcellus Area. We are the operator of approximately 93% of our proved reserves within the Utica Core Area and our Marcellus Area. Additionally, we own approximately 107,000 net acres (which are approximately 71% held by production) outside of the Utica Core Area that may be prospective for the oil window of the Utica Shale.

Utica Shale

The Ordovician-aged Utica Shale is an unconventional reservoir comprised of organic-rich black shale, with most production occurring at vertical depths between 6,000 and 10,000 feet. The richest and thickest concentration of organic-carbon content is present within the Point Pleasant layer of the Lower Utica formation. Across the Utica Core Area, the eastern boundary is more thermally mature and expected to produce dry gas, while the western boundary is less thermally mature and expected to produce a greater proportion of condensate and NGLs in addition to natural gas. We classify our acreage between these boundaries as being prospective for Dry Gas, Rich Gas, or Condensate.

Marcellus Shale

The Marcellus Shale consists of organic-rich black shale, with most production occurring at vertical depths between 5,000 and 8,000 feet. As of December 31, 2017, we had approximately 15,500 net acres in the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as our Marcellus Area. The reservoir underlying this acreage is less thermally mature than the Marcellus Shale in Southwestern Pennsylvania, and consequently, we believe natural gas production from this area will yield significant NGLs and condensate.

Activity

Through December 31, 2017, we, or our operating partners, had commenced drilling 234 gross wells within the Utica Core Area and our Marcellus Area, which are summarized below:

Type	Operated Gross Wells			Type	Non-Operated Gross Wells		
	Producing	Awaiting	Awaiting		Producing	Awaiting	Awaiting
Curve Area				Drilling			Drilling

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	to Sales ⁽¹⁾	Turn to Sales	Completion/ Completing		to Sales	Turn to Sales	Completion/ Completing	
Dry Gas	38	—	2	2	30	—	—	—
Rich Gas	—	—	—	—	22	—	—	—
Condensate	63	—	12	5	55	—	—	—
Total Utica Core Area	101	—	14	7	107	—	—	—
Marcellus Condensate ⁽¹⁾	1	2	—	—	1	—	—	—
Marcellus Area	1	2	—	—	1	—	—	—
Total	102	2	14	7	108	—	—	—

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(1)Excludes one Marcellus producing well outside our defined type curve area.

As of December 31, 2017, our estimated proved reserves were 1,458.6 Bcfe, or 243.1 MMBoe, an increase of 211% from December 31, 2016 reserves of 469.4 Bcfe, or 78.2 MMBoe, based on reserve reports prepared by Netherland, Sewell & Associates, Inc., or NSAI, our independent petroleum engineers. As of December 31, 2017, our estimated proved reserves were approximately 75% natural gas, 17% NGLs and 8% oil, and approximately 31% were proved developed reserves. The following table provides information regarding our proved reserves as of December 31, 2017, 2016, and 2015:

	Estimated Total Proved Reserves								
	Natural Gas	Oil	NGLs	Total	Total	%	%		
	(Bcf)	(MMBbls)	(MMBbls)	(Bcfe)	(MMBoe)	Liquids	Developed		
December 31, 2015	274.1	4.7	7.8	348.8	58.1	21.4 %	79.8 %		
December 31, 2016	386.4	5.2	8.7	469.4	78.2	17.7 %	63.4 %		
December 31, 2017	1,090.1	19.5	41.9	1,458.6	243.1	25.3 %	31.3 %		

Net Undeveloped Locations

The following table provides a summary of our approximate net acreage, net producing locations and net undeveloped locations as of December 31, 2017:

	As of December 31, 2017		
	Approximate Net Acreage	Net Producing Locations	Net Undeveloped Locations ⁽¹⁾
Dry Gas	48,051	37.4	98.2
Rich Gas	8,046	2.8	18.3
Condensate	39,672	66.7	93.8
Marcellus Condensate ⁽²⁾	15,456	0.6	78.1
Total	111,225	107.5	288.4

(1)Based on our reserve report as of December 31, 2017, we had 85 net drilling locations associated with proved undeveloped reserves and 13 net locations associated with proved developed non-producing reserves. Please see “—Determination of Drilling Locations” for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Our drilling locations are also scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill our drilling locations. Please see “Item 1A. Risk Factors” for more information.

(2)Excludes one Marcellus producing well outside our defined type curve area.

Determination of Drilling Locations

Net undeveloped locations are calculated by taking our total net acreage and multiplying such amount by a risk factor, which is then divided by our expected well spacing. In each type curve area, we apply a 10% risk factor to our net acreage to account for inefficient unitization, acreage expirations and the risk associated with our inability to force pool under state law. We then subtract net producing wells to arrive at net undeveloped locations.

• Undeveloped Net Dry Gas Locations – We assume these locations have 16,000 foot laterals and 1,000 foot spacing between wells which yields approximately 374 acre spacing. As of December 31, 2017, we had approximately 48,051 net acres in the Dry Gas area, which, after removing net producing locations, results in 98.2 net undeveloped locations.

- Undeveloped Net Rich Gas Locations – We assume these locations have 16,000 foot laterals and 1,000 foot spacing between wells which yields approximately 374 acre spacing. As of December 31, 2017, we had approximately 8,046 net acres in the Rich Gas area, which, after removing net producing locations, results in 18.3 net undeveloped locations.

Undeveloped Net Condensate Locations – We assume these locations have 16,000 foot laterals and 750 foot spacing between wells which yields approximately 281 acre spacing. As of December 31, 2017, we had approximately 39,672 net acres in the Condensate area, which, after removing net producing locations, results in 93.8 net undeveloped locations.

Undeveloped Net Marcellus Condensate Locations – We assume these locations have 10,000 foot laterals and 750 foot spacing between wells which yields approximately 177 acre spacing. As of December 31, 2017, we had approximately 15,456 net acres in the Marcellus Condensate area, which, after removing net producing locations, results in 78.1 net undeveloped locations.

Midstream Agreements

We work closely with our midstream partners to coordinate our drilling and completion schedule with their well hook up and facility construction schedule to ensure sufficient capacity is available to minimize any delays in turning production into sales.

We have contracted for firm gathering, processing and fractionation capacity for a significant portion of our operated acreage in the Condensate and Rich Gas Windows of the Utica Core Area with Blue Racer Midstream, LLC (“Blue Racer”), a joint venture between Dominion Resources, Inc. and Caiman Energy II, LLC. This gas-processing agreement does not require us to make minimum volume deliveries or shortfall payments. Additionally, we have contracted with Eureka Midstream LLC (“Eureka Midstream”) for firm gathering services on a significant portion of our operated acreage in the Dry Gas area of the Utica Core Area.

We work closely with our midstream partners to coordinate our drilling and completion schedule with their well hook up and facility construction schedule to ensure sufficient capacity is available to minimize any delays in turning production into sales.

The following table illustrates the natural gas firm transportation and sales volumes associated with our operated assets:

Firm Sales & Transportation	Start Date	Term	Volume (Dth/d)	Market
Columbia Gas Transmission				
("TCO")	October 2016	15 years	205,000	TCO Pool
Rover Pipeline System ⁽¹⁾	May 2018	15 years	100,000	Gulf Coast
Rover Pipeline System ⁽¹⁾	May 2018	15 years	50,000	Canada

(1) Anticipated start date based on public statements from Energy Transfer Partners.

In March 2014, we entered into a 20-year contract with Shell Chemical, LP (“Shell Chemical”) for the sale of ethane to Shell Chemical’s proposed Appalachian cracker project in Monaca, Pennsylvania. Under the terms of the contract, we agreed to sell to Shell Chemical, at a minimum, all of our “Must Recover Ethane” (i.e., 30% of total recoverable ethane) at Blue Racer’s fractionation facility near Natrium, West Virginia. In June 2016, Shell Chemical provided notice of a positive final investment decision and election to purchase our ethane.

In August 2014, we entered into an agreement with EnLink Midstream Operating, LP (“EnLink Midstream”) for the marketing of our condensate and operation of our condensate stabilization facilities. Under the terms of the agreement, among other things, EnLink Midstream purchased two of our existing condensate stabilization facilities, and plans to construct and operate additional facilities to support our drilling program in the Utica Shale. This midstream agreement requires us to make minimum volume deliveries to the condensate stabilization facilities or shortfall payments. The following table illustrates the minimum volume commitments under our agreement with EnLink Midstream:

Natural Gas		Oil		Water	
Term	(Mcf/d)	Term	(Bbl/d)	Term	(Bbl/d)
				January 2018 – May 2019	
January 2018 – May 2018	60,800	January 2018 – March 2018	3,000		5,000
June 2018 – June 2018	89,300	April 2018 – July 2018	6,000		
July 2018 – December 2018	117,800	August 2018 – June 2020	10,052		
January 2019 – December 2019	92,400				
January 2020 – June 2020	82,300				

In January of 2018, we amended our firm gas gathering services agreement with Eureka Midstream to gather and compress a substantial portion of our operated production of Dry Gas through Eureka Midstream’s system. This new agreement replaces an existing agreement with Eureka Midstream that we had entered into in 2013. Under the new 20-year agreement, we will have firm gathering capacity, which increases during the term of the agreement, from between approximately 275 MMcf to 900 MMcf per day. This agreement provides for reduced gathering and compression charges, which will be effective immediately. Through this agreement, we obtained access to additional downstream pipelines and markets connected to Eureka including the Rover Pipeline System accessing our new firm transportation capacity. This midstream agreement requires us to make minimum volume deliveries to the Eureka Midstream gathering system or shortfall payments. The following table illustrates the minimum volume commitments under our agreement with Eureka Midstream:

Natural Gas	
Term	(Mcf/d)
January 2018 – December 2018	180,000
January 2019 – December 2019	212,500
January 2020 – December 2020	310,000
January 2021 – December 2021	355,000
January 2022 – December 2022	400,000

In December 2014, we entered into a 10-year firm transportation and marketing agreement with Blue Racer to market a substantial portion of our operated production of propane and butane through Blue Racer's firm capacity on Sunoco's Mariner East II Project. The Mariner East II Project will connect the NGLs resources in the Marcellus and Utica Shale to Sunoco's existing infrastructure and international port at its Marcus Hook facility near Philadelphia. Mariner East II is expected to be operational in 2018. Under the agreement, we will have firm transportation, which increases during the term of the agreement, from between approximately 7,500 barrels to 14,000 barrels per day (67% propane and 33% butane). Through this agreement, we plan to export propane and butane in order to potentially capture the premium pricing offered by international markets, but also retain the ability to sell domestically.

In April 2017, we entered into a 2-year hauling and marketing agreement with Marathon Petroleum ("Marathon") to sell condensate volumes. As a part of this contract, Marathon will pick up the produced condensate at our stabilization facilities and well pads and haul it away utilizing their own fleet of vehicles or third-party services. The title and risk of loss will pass to Marathon at the intake flange of our stabilization facilities under the terms of this contract.

As of December 31, 2017, our natural gas firm transportation commitments through 2022 include:

Volume of		
Natural Gas Volume of		
Year Ended December 31,	(MMBtu/d)	NGLs (Bbls/d)
2018	318,014	5,590
2019	355,000	10,739
2020	355,000	10,724
2021	355,000	9,310
2022	355,000	8,115

The minimum demand fees related to these volume and firm transportation agreements that were in place as of December 31, 2017 are reflected in our table of contractual obligations. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Cash Contractual Obligations.” See “Item 1A. Risk Factors” for a discussion of risks and uncertainties relating to our gathering, processing and fractionation arrangements.

Recent Developments

Drilling Joint Venture

On December 22, 2017, we entered into definitive agreements with Sequel Energy Group LLC (“Sequel”) (an affiliate of GSO Capital Partners LP) to establish a drilling joint venture on our Utica Shale acreage in Guernsey and Monroe Counties in southeast Ohio. We have committed funding from Sequel of up to \$285 million to fund its proportionate share of two drilling programs comprising of 33 gross wells in aggregate, with the mutual option for an additional third well program consisting of approximately 16 wells (which would increase the committed funding). We will retain 50% of our pre-carry working interest in the first program and 30% of our pre-carry working interest in the second program. We have the option to adjust our pre-carry working interest in the third program, if applicable, to between 30% to 70%, which must be exercised prior to the commencement of the third program. We will receive a 15% carried interest on drilling and completion capital expenditures incurred in each well program, which will be proportionately reduced based upon our retained pre-carry working interest in such well program, and a significant portion of Sequel’s working interest in each well program will revert to Eclipse once a certain return is realized by Sequel in each program. We will be the operator of all wells drilled within each well program.

Flat Castle Acquisition

On January 18, 2018, Eclipse Resources-PA, LP, a wholly owned subsidiary of the Company, completed its acquisition of certain oil and gas leases, wells and other oil and gas rights and interests covering approximately 44,500 net acres located in the counties of Tioga and Potter in the Commonwealth of Pennsylvania (such transaction, the “Flat Castle Acquisition”) from Travis Peak Resources, LLC. The aggregate adjusted purchase price for the Flat Castle Acquisition was \$92.2 million, which was paid entirely with approximately 37.8 million shares of the Company’s common stock. The Flat Castle Acquisition includes one producing well, increases our drilling location count by approximately 87 net drilling locations ⁽¹⁾, and significantly expands our Utica Shale dry gas acreage. In addition, on December 8, 2017, Eclipse Resources Midstream, LP, a wholly owned subsidiary of the Company (“Eclipse Midstream”), acquired the exclusive right and option to purchase all of the outstanding equity interests of Cardinal NE Holdings, LLC, which owns midstream infrastructure with associated gathering rights on the acreage acquired in the Flat Castle Acquisition, from Cardinal Midstream II, LLC for an aggregate purchase price of \$18.3 million in cash. The option granted to Eclipse Midstream expires as of the close of business on June 30, 2018 if not exercised prior to such time.

(1) Please see “—Determination of Drilling Locations” for more information regarding the process and criteria through which these drilling locations were identified.

Tax Reform

New tax legislation, commonly referred to as the Tax Cuts and Jobs Act, was enacted on December 22, 2017. ASC 740, Accounting for Income Taxes, requires companies to recognize the effect of tax law changes in the period of enactment even though the effective date for most provisions is for tax years beginning after December 31, 2017. Adjustments to our tax provision that were recorded in the three months ended December 31, 2017 principally relate to the reduction in the U.S. corporate income tax rate to 21%, which resulted in the Company recognizing a \$142 million reduction of tax benefit to remeasure deferred tax assets that will reverse at the new 21% rate. Other significant provisions that are not yet effective but may impact incomes taxes in future years include: the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income, a limitation on utilization of net operating losses generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of net operating losses generated after tax year 2017, the repeal of the corporate Alternative Minimum Tax, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to our ability to expense intangible drilling costs and the utilization of our net operating loss carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation, which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation, may have a significant effect on this projection.

2018 Capital Budget

Our Board of Directors recently approved an initial capital budget for 2018 of between approximately \$300 - \$320 million, allocated approximately 84% for drilling and completions activities, 8% for midstream activities, 6% for land activities and 2% for other capital requirements. The 2018 capital budget is expected to be substantially funded through internally generated cash flows, the Company’s current cash balance, proceeds from our drilling joint venture, borrowings under the revolving credit facility and/or other debt and equity offerings.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Proved Reserves. Our historical proved reserve estimates were prepared by NSAI. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regard to 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. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of NSAI's proved reserve reports as of December 31, 2017, December 31, 2016 and December 31, 2015 are attached hereto as exhibits.

We maintain an internal staff of engineers and geoscience professionals who work closely with NSAI to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets. Our internal technical team members meet with NSAI periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information for our properties to NSAI, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Michael Lynch, our Vice President, Reservoir Engineering, is primarily responsible for overseeing the preparation of all of our reserve estimates. Mr. Lynch is an engineer with over 30 years of reservoir, completions and operations experience and our reservoir engineering staff has an average of approximately eight years of industry experience per person.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by Mr. Lynch or under his direct supervision;
- review by Mr. Lynch of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions by our Chief Executive Officer, Chief Operating Officer, Chief Financial Officer and Executive Vice President, Corporate Development and Geosciences;
- direct reporting responsibilities by Mr. Lynch to our Chief Operating Officer; and
- verification of property ownership by our land department.

The reserves estimates shown herein are based upon evaluations prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Steven W. Jansen and Mr. Edward C. Roy III. Mr. Jansen, a Licensed Professional Engineer in the State of Texas (No. 112973), has been practicing consulting petroleum engineering at NSAI since 2011 and has over 4 years of prior industry experience. He graduated from Kansas State University in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Roy, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 2364), has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. He graduated from Texas Christian University in 1992 with a Bachelor of Science Degree in Geology and from Texas A&M University in 1998 with a Master of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2017, December 31, 2016 and December 31, 2015 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production

performance-based methods; (2) material balance-based methods;

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(3) volumetric-based methods and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties.

To estimate economically recoverable proved reserves and related future net cash flows, NSAI considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Summary of Natural Gas, NGLs and Oil Reserves. The following table presents our estimated net proved natural gas, NGLs and oil reserves as of December 31, 2017, December 31, 2016 and December 31, 2015, based on the proved reserve reports prepared by NSAI, our independent petroleum engineers, and such proved reserve reports have been prepared in accordance with the rules and regulations of the SEC. Our estimated proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December for the years 2017, 2016, and 2015. For oil and NGLs volumes, the average WTI spot price of \$51.34 per barrel for December 31, 2017, \$42.75 per barrel for December 31, 2016 and \$50.28 per barrel for December 31, 2015, has been adjusted by property group for quality, transportation fees and regional price differentials. For gas volumes, the average NYMEX Henry Hub spot price of \$2.98 per MMBtu for December 31, 2017, \$2.48 per MMBtu for December 31, 2016 and \$2.59 per MMBtu for December 31, 2015 has been adjusted by property group for energy content, transportation fees and regional price differentials. All prices are held constant throughout the lives of the properties. All of our proved reserves are located in the United States. Copies of the proved reserve reports as of December 31, 2017, December 31, 2016 and December 31, 2015 prepared by NSAI with respect to our properties are included as exhibits to this Annual Report. Our estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the SEC.

	2017	2016	2015
Proved Developed Reserves:			
Natural gas (Bcf)	334.6	226.1	209.5
NGLs (MBbls)	13,782.9	7,520.0	7,245.7
Oil (MBbls)	6,449.6	4,439.5	4,239.2
Combined (Bcfe)	456.0	297.8	278.4
Proved Undeveloped Reserves:			
Natural gas (Bcf)	755.5	160.4	64.5
NGLs (MBbls)	28,147.7	1,155.5	513.0

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Oil (MBbls)	13,031.2	718.1	453.9
Combined (Bcfe)	1,002.6	171.6	70.3
Proved Reserves:			
Natural gas (Bcf)	1,090.1	386.4	274.1
NGLs (MBbls)	41,930.6	8,675.5	7,758.7
Oil (MBbls)	19,480.8	5,157.7	4,693.1
Combined (Bcfe)	1,458.6	469.4	348.8

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of natural gas, NGLs and oil that are ultimately recovered. Estimates of economically recoverable natural gas, NGLs and oil and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read “Item 1A. Risk Factors” appearing elsewhere in this Annual Report.

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included in “Item 8. Financial Statements and Supplementary Data” and the proved reserve reports as of December 31, 2017, 2016, and 2015, which are included as exhibits to this Annual Report.

Proved Reserves Additions and Revisions

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of net proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	Natural Gas	NGLs	Oil	Total
	(Bcf)	(MBbls)	(MBbls)	(Bcfe)
Proved Reserves:				
December 31, 2014	256.3	10,879.0	5,697.4	355.8
Reserve revisions	(115.3)	(4,705.7)	(1,550.1)	(152.9)
Extensions and discoveries	182.6	4,035.7	2,496.3	221.7
Production	(49.5)	(2,450.3)	(1,950.5)	(75.8)
December 31, 2015	274.1	7,758.7	4,693.1	348.8
Reserve revisions	(0.1)	1,273.7	1,196.8	14.8
Extensions and discoveries	175.4	2,156.0	1,300.2	196.1
Acquisitions	3.8	24.8	15.1	4.1
Divestitures	(5.9)	(91.5)	(703.7)	(10.7)
Production	(60.9)	(2,446.2)	(1,343.8)	(83.7)
December 31, 2016	386.4	8,675.5	5,157.7	469.4
Reserve revisions	515.1	20,327.3	9,746.8	695.6
Extensions and discoveries	274.4	15,598.8	6,192.9	405.1
Acquisitions	1.6	42.6	5.8	1.9
Production	(87.4)	(2,713.6)	(1,622.4)	(113.4)
December 31, 2017	1,090.1	41,930.6	19,480.8	1,458.6

During the year ended December 31, 2017, we increased proved reserves by 989.2 Bcfe compared to the year ended December 31, 2016, primarily through revisions, extensions and discoveries and acquisitions. This increase in proved

reserves was comprised of 405.1 Bcfe of extensions and discoveries, 695.6 Bcfe of revisions, and 1.9 Bcfe of acquisitions. The increase was offset by 113.4 Bcfe of production. The revisions consisted of positive revisions of 27.0 Bcfe due to technical adjustments and 668.6 Bcfe due to pricing and differential changes.

Future Net Cash Flows. At December 31, 2017, 2016, and 2015, the standardized measure of estimated future net cash flows after income taxes from our proved reserves was \$729.7 million, \$206.0 million and \$212.9 million, respectively. At December 31, 2017, 2016, and 2015, the PV-10 value of estimated future net cash flows before income taxes from our proved reserves was \$729.7 million, \$206.0 million and \$212.9 million, respectively. These PV-10 values were calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves.

The following table sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV-10) and the present value of those net cash flows after income tax (standardized measure):

(In thousands)	Year Ended December 31,		
	2017	2016	2015
Future net cash flows	\$1,538,529	\$300,430	\$300,059
Present value of future net cash flows:			
Before income tax (PV-10)	\$729,686	\$205,981	\$212,865
Income taxes	—	—	—
After income tax (standardized measure)	\$729,686	\$205,981	\$212,865

PV-10 is a non-GAAP financial measure and generally differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our oil and natural gas properties. We, and others, in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. We believe that the presentation of the pre-tax PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our reserves prior to taking into account corporate income taxes and our current tax structure.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2017, our proved undeveloped reserves were comprised of 13,031.2 MBbls of oil, 755.5 Bcf of natural gas and 28,147.7 MBbls of NGLs, for a total of 1,002.6 Bcfe. As of December 31, 2016, our proved undeveloped reserves were comprised of 718.1 MBbls of oil, 160.4 Bcf of natural gas and 1,155.5 MBbls of NGLs, for a total of 171.6 Bcfe. As of December 31, 2015, our proved undeveloped reserves were comprised of 453.9 MBbls of oil, 64.5 Bcf of natural gas and 513.0 MBbls of NGLs, for a total of 70.3 Bcfe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during 2015, 2016, and 2017 (in Bcfe):

Balance, December 31, 2014	159.0
Reserve revisions ⁽¹⁾	(134.5)
Extensions and discoveries	55.2
Transfers to proved developed	(9.4)
Balance, December 31, 2015	70.3
Reserve revisions ⁽²⁾	(14.2)
Acquisitions	3.6
Extensions and discoveries	111.9
Balance, December 31, 2016	171.6
Reserve revisions ⁽³⁾	528.5
Acquisitions	1.3
Extensions and discoveries	391.2

Transfers to proved developed	(90.0)
Balance, December 31, 2017	1,002.6

(1) Revisions to previous estimates are comprised of 19.6 Bcfe of positive technical revisions, 0.3 Bcfe positive revision related to differentials, 0.7 Bcfe negative revision due to expense assumptions, 121.8 Bcfe negative price revisions, and 31.9 Bcfe negative revisions due to reclassification of wells to unproved because of a slower pace of development beyond the five-year development horizon. The positive technical revisions were primarily due to improved well performance from offsetting producing wells, which we believe were mainly due to improvements in well completion design and pressure managed production techniques.

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- (2) Revisions to previous estimates are comprised of 16.6 Bcfe of positive technical revisions primarily due to well performance, 20.2 Bcfe of negative revisions related to pricing and differential changes, and negative revisions of 10.6 Bcfe due to economic locations that the Company no longer expects to develop within five years of initial classification.
- (3) Revisions to previous estimates are comprised of 91.1 Bcfe of negative technical revisions primarily due to well performance, 620.6 Bcfe of positive revisions related to pricing and differential changes, and negative revisions of 1.0 Bcfe due to expense assumption changes.

During the year ended December 31, 2017, we converted approximately 90.0 Bcfe, or 52% of our proved undeveloped reserves as of December 31, 2016, to proved developed reserves at a capital cost of approximately \$34 million. Estimated future development costs relating to the development of our proved undeveloped reserves as of December 31, 2017 are approximately \$835 million over the next five years.

Production and Price History

The following table sets forth information regarding net production of natural gas, NGLs and oil, and certain price and cost information for the periods indicated:

	Year Ended December 31,		
	2017	2016	2015
Total production volumes:			
Natural gas (MMcf)	87,404.2	60,921.9	49,477.6
NGLs (MBbls)	2,713.7	2,446.2	2,450.3
Oil (MBbls)	1,622.4	1,343.8	1,950.5
Combined (MMcfe)	113,420.8	83,661.9	75,882.4
Average daily production volumes:			
Natural gas (Mcf/d)	239,464	166,453	135,555
NGLs (Bbls/d)	7,435	6,684	6,713
Oil (Bbls/d)	4,445	3,672	5,344
Combined (Mcfe/d)	310,744	228,589	207,897
Average Realized Price (including cash settled derivatives and firm transportation):			
Natural gas (\$/Mcf)	\$2.34	\$2.19	\$2.95
NGLs (\$/Bbl)	21.96	15.55	12.32
Oil (\$/Bbl)	46.14	44.66	38.38
Combined (\$/Mcfe)	\$2.99	\$2.76	\$3.38
Expenses (per Mcfe):			
Lease operating	\$0.18	\$0.11	\$0.18
Transportation, gathering and compression	1.10	1.30	1.13
Production, severance and ad valorem taxes	0.07	0.09	0.05
Depletion, depreciation and amortization	1.05	1.11	3.23
General and administrative	0.39	0.47	0.61

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2017 relating to our leasehold acreage. Developed acres are acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Area	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net ⁽¹⁾	Gross	Net ⁽¹⁾	Gross	Net ⁽¹⁾
Ohio	175,878	137,677	94,134	64,954	270,012	202,631
Total	175,878	137,677	94,134	64,954	270,012	202,631

(1) Fossil Creek owns a right to participate for a 12.5% working interest in approximately 2,812 gross acres within our area of mutual interest with Antero Resources. In calculating our net acreage, we have assumed that Fossil Creek will elect to participate in all wells in which they have a right to participate for their full interest and have deducted this 12.5% working interest from our net acreage where applicable.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms, although approximately 68% of our leases in the Utica Core Area have a 3-5 year extension at our option. The following table sets forth the total gross and net undeveloped acres as of December 31, 2017 that will expire over the next five years unless operations have commenced on the leasehold acreage or lands pooled therewith have been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities:

Year Ending December 31,	Gross Acres	Net Acres
2018	33,069	21,473
2019	12,339	9,760
2020	3,320	2,657
2021	14,570	11,919
2022 and beyond	14,657	11,685

In 2018, we expect to incur approximately \$28 million related to delay rentals and lease extensions related to acreage that would otherwise expire during 2018.

Drilling Results

The following table sets forth information with respect to the number of wells completed during the years indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	2017		2016		2015	
	GrossNet		GrossNet		GrossNet	
Development Wells:						
Productive	25	22.2	22	18.1	76	33.9
Dry holes	—	—	—	—	—	—
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Total:						
Productive	25	22.2	22	18.1	76	33.9
Dry holes	—	—	—	—	—	—

All of these productive wells are gas wells. Many of our gas wells also produce oil, condensate and NGLs. As of December 31, 2017, we had 23 gross (15.9 net) wells in the process of drilling, completing or shut in awaiting infrastructure that are not reflected in the above table.

Operations

General

As of December 31, 2017, we operated approximately 93% of our proved reserves. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Major Customers

For the year ended December 31, 2017, sales to Emera Energy Services and Marathon represented approximately 17% and 10% of our total sales, respectively. For the year ended December 31, 2016, sales to Sequent Energy Management, EnLink Midstream, Antero Resources and Concord Energy LLC represented approximately 20%, 17%, 14%, and 12% of our total sales, respectively. For the year ended December 31, 2015, sales to EnLink Midstream, Sequent Energy Management, Antero Resources and ARM Energy Management represented approximately 21%, 19%, 19%, and 11% of our total sales, respectively. Although a substantial portion of production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as other customers or markets would be accessible to us.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often-cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;

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- obligations or duties under applicable laws;
- development obligations under natural gas leases;
- net profits interests;
- mortgages by a lessor; or
- rights of way or easements held by third parties such as utilities.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, some natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies do in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Emerging Growth Company Status

We are an “emerging growth company” as defined in the Jumpstart Our Business Startups Act, or the JOBS Act. For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies under the JOBS Act, we are not required to, among other things:

- provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold stockholder advisory votes on executive compensation as required by the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act; or
- obtain stockholder approval of any golden parachute payments not previously approved.

We will cease to be an “emerging growth company” upon the earliest of:

- the last day of the fiscal year in which we have \$1.07 billion or more in annual revenues;
- the date on which we become a “large accelerated filer” (the fiscal year end on which the total market value of our common equity securities held by non-affiliates is \$700.0 million or more as of June 30);
- the date on which we issue more than \$1.0 billion of non-convertible debt over a 3-year period; or
- the last day of the fiscal year following the 5th anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the Securities Act, for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period, and as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing natural gas and oil properties have statutory provisions regulating the exploration for and production of natural gas and oil, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment 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 number of wells that may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratable or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe that we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict our future ability to comply with applicable law and regulations or the future costs or impact of compliance.

Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, or FERC, and the courts. We cannot predict the substance or outcome of such proposals and proceedings or when or whether any such proposals may become effective. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Natural Gas and Oil

The production of natural gas and oil is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the

amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill; although in some cases we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, NGLs and oil within its jurisdiction.

We own interests in properties located onshore in two U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas. The failure to comply with these rules and regulations can result in substantial penalties.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation (including storage services) and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce and the revenues we receive for sales of our natural gas.

FERC's current policies allow for the sale of natural gas by producers at market-based prices. However, Congress could enact price controls in the future. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by FERC. In some limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The Energy Policy Act of 2005, or the EPAct 2005, among other matters, amended the NGA to add an anti-manipulation provision, which makes it unlawful for any entity, directly or indirectly, to use or employ, in connection with the purchase or sale of natural gas or the purchase of natural gas transportation services subject to FERC jurisdiction, any manipulative or deceptive device or contrivance of such rules and regulations as FERC may prescribe as necessary in the public interest or for the protection of natural gas ratepayers. Furthermore, EPAct 2005 provides FERC with additional civil penalty authority. The EPAct 2005 provides FERC with the power to assess civil penalties of up to \$1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the Natural Gas Policy Act, or NGPA, from \$5,000 per violation per day to \$1,000,000 per violation per day. These civil penalty amounts under the NGA and NGPA have been adjusted in accordance with the Federal Civil Penalties Inflation Adjustment Act of 1990, as amended by the Federal Civil Penalties Inflation Adjustment Improvements Act of 2015, from \$1,000,000 per violation per day to \$1,238,271 per violation per day.

On January 19, 2006, FERC issued Order No. 670 to implement the anti-manipulation provision of the EPAct 2005. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made, in light of the circumstances under which they were made, not misleading; or (3) engage in any act, practice or course of business that operates, or would operate, as a fraud or deceit upon any entity. The anti-manipulation rule applies to "any entity", including otherwise non-jurisdictional entities, and may include activities that relate to intrastate or other non-jurisdictional sales or gathering, to the extent such activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at

wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting. Reporting required under Order 704 is considered to constitute an activity conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

We cannot reliably predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts and new proposals and proceedings are likely to arise. The natural gas industry historically has been very heavily regulated and changing conditions and experience has led to changes in such regulation. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other, similarly situated, natural gas producers.

Gathering service is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which can increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA excludes natural gas gathering facilities from regulation by FERC under the NGA. Further, an entity is not subject to regulation under NGA by FERC as a "natural gas company" solely by virtue of such entity owning or operating such facilities. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to determine that the owner/operator of such facilities is not subject to regulation as a natural gas company under the NGA. However, FERC orders may affect the distinction between FERC-regulated transmission services and federally unregulated gathering services, which is the subject of ongoing litigation. Furthermore, Congress has discretion to revise the jurisdictional line. Consequently, the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to certain requirements under the Commodity Exchange Act, or CEA, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action Congress or FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other, similarly situated, natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

General

Our operations are subject to numerous federal, regional, state, local, and other laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Resource Conservation and Recovery Act, or RCRA, the Clean Water Act, or the CWA, and the Clean Air Act, or the CAA. These laws and regulations, along with state analogs, govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs.

In addition, public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, the EPA's 2014—2016 National Enforcement Initiatives include "Ensuring Energy Extraction Activities Comply with Environmental Laws." The EPA has retained this category as a National Enforcement Initiative for fiscal years 2017 through 2019. According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." The EPA has emphasized that this initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large-scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Noncompliance could also result in an increase in capital expenditures or reduced earnings and hurt our ability to compete in the marketplace. Accidental releases or spills may occur in the course of our operations, and we cannot be sure that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The Safe Drinking Water Act and the Underground Injection Control Program

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act, or the SDWA, over hydraulic fracturing activities involving the use of diesel fuel. From time to time, however, Congress has proposed legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of all hydraulic fracturing activities, as well as to require disclosure of the chemical constituents of

the fluids used in the fracturing process. Scrutiny of hydraulic fracturing activities by the EPA continues in other ways, with the EPA having completed a final report for a multi-year study of the potential environmental impacts of hydraulic fracturing. In addition, in June 2016, the EPA published final regulations under the CWA for wastewater discharges associated with unconventional oil and natural gas resources, such as low permeability and porosity formations. Moreover, on March 20, 2015, the U.S. Department of the Interior finalized updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. The Department of the Interior has also finalized rules to minimize venting and flaring from wells on federal lands. Although the hydraulic fracturing rule has been rescinded and the venting and flaring rule has been delayed, and is now proposed to be replaced, these rules could be reinstated through litigation and replacement rules could result in material compliance obligations. Other governmental agencies, including the United States Department of Energy have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could

spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. In Ohio, the Department of Natural Resources finalized new horizontal well site construction requirements on July 6, 2015. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless regulations can be expected to become stricter in the future, and, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Hazardous Substances and Wastes

CERCLA, also known as the “Superfund law,” imposes cleanup obligations, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed, or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA and any state analogs may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While petroleum and crude oil fractions are not considered hazardous substances under CERCLA and its analog because of the so-called “petroleum exclusion,” adulterated petroleum products containing other hazardous substances have been treated as hazardous substances in the past.

The RCRA regulates the generation and disposal of solid wastes and hazardous wastes. The RCRA specifically excludes from the definition of hazardous waste “drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy.” These materials are currently regulated as non-hazardous solid wastes. However, legislation has been proposed from time to time that could reclassify certain natural gas and oil exploration and production wastes as “hazardous wastes,” which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, some ordinary industrial wastes that we generate, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous wastes.

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials, or NORM, may affect our operations. For example, the Ohio Department of Natural Resources has asked operators to identify technologically enhanced NORM, or TENORM, in their processes, such as hydraulic fracturing sand, recycled drilling mud, and spent tank bottoms. Local landfills only accept such waste when it meets their TENORM standards. As a result, we may have to locate out-of-state landfills to accept TENORM waste from time to time, potentially increasing our disposal costs.

Some of our leases may have had prior owners who commenced exploration and production of natural gas and oil operations on these sites. Although we have utilized operating and disposal practices that were standard in the industry

at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the RCRA, and/or analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Waste Discharges

The CWA and its state analog impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Air Emissions

The CAA and its state analog and regulations restrict the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. On April 17, 2012, the EPA also approved final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through reduced emission (or “green”) completions, or flaring where green completions are not feasible. The rules also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas-processing plants, and certain other equipment. In May 2016, the EPA finalized amendments that expand the requirements of the 2012 rule to methane emissions and air emissions associated with hydraulic fracturing operations for oil wells. The EPA is continuing to consider other aspects of the new rules and may propose additional amendments. In addition, the U.S. Department of Interior finalized rules to reduce venting and flaring from oil and natural gas operations located on federal lands. In February of 2018, the Department of the Interior is proposing to revise the venting and flaring rules. A revised rule may require a number of modifications to our own operations, including the installation of new equipment to control emissions. In addition, it is possible that litigation will force the Department of the Interior to implement the current version of the rule. Compliance with such rules could result in additional costs for us and our customers, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

Oil Pollution Act

The Oil Pollution Act of 1990, or the OPA, and regulations thereunder impose a variety of requirements on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A “responsible party” includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or the NEPA. The NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments, which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. The NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and

development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Endangered Species Act and Migratory Bird Treaty Act

The Endangered Species Act, or the ESA, and similar applicable state legislation restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Moreover, as a result of a settlement approved by the United States District Court for the District of Columbia in September 2011, the United States Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. For example, regulations designed to protect the Indiana bat (*Myotis soldalis*), which is an endangered species protected by the ESA and similar state legislation, restrict or increase the cost of our operations by, among other things, limiting our ability to clear trees to establish rights of way or pad locations on some of our acreage during certain periods of the year. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds we believe that we are in substantial compliance with the ESA, similar applicable state legislation and the Migratory Bird Treaty Act, and we are not aware of any proposed ESA listings that will materially 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.

Worker Safety

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

Employees

As of December 31, 2017, we had 171 full-time employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We utilize the services of independent contractors to perform various field and other services.

Corporate Information

Our principal executive offices are located at 2121 Old Gatesburg Road, Suite 110, State College, Pennsylvania 16803, and our telephone number is (866) 590-2568. Our website is www.eclipseresources.com. We expect to make our periodic reports and other information filed with, or furnished to, the Securities and Exchange Commission, or the SEC, available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with, or furnished to, the SEC. The information on or otherwise accessible through, our website or any other website does not constitute a part of this Annual Report.

You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at www.sec.gov. Our common stock is listed and traded on the New York Stock Exchange under the symbol "ECR." Our reports, proxy statements and other information filed with the

SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

Item 1A. RISK FACTORS

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report, actually occur, our business, financial condition or results of operations could suffer. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect our company.

Risks Related to Our Business

Natural gas, NGLs and oil prices have been volatile and have declined from recent historical highs. If commodity prices remain depressed for a lengthy period of time or experience a further substantial or extended decline, our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments may be adversely affected.

The prices we receive for our natural gas, NGLs and oil production heavily influence our revenue, operating results profitability, access to capital, future rate of growth and carrying value of our properties. Natural gas, NGLs and oil are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities markets have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide and regional economic conditions impacting the global supply of and demand for natural gas, NGLs and oil;
- the price and quantity of imports of foreign natural gas, including liquefied natural gas, foreign oil and refined products;
- the price and quantity of exported domestic crude oil, natural gas, including liquefied natural gas, NGLs and refined products;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indexes in the areas in which we operate and expectations about future commodity prices;
- the actions of the Organization of the Petroleum Exporting Countries;
- the proximity, capacity, cost and availability of gathering and transportation facilities, and other factors that result in differentials to benchmark prices;
- the cost of exploring for, developing, producing and transporting reserves;
- speculative trading in natural gas and crude oil derivative contracts;
- risks associated with operating drilling rigs;
- increased end-user conservation or conversion of alternative fuels;
- the price and availability of competitors' supplies of natural gas, NGLs, oil and alternative fuels;
- localized and global supply and demand fundamentals and transportation availability;
- adverse or severe weather conditions and other natural disasters;
- technological advances affecting energy consumption and production; and
- domestic, local and foreign governmental regulation and taxes.

In addition, substantially all of our natural gas production and oil production is sold to purchasers under contracts with market-based prices based on NYMEX Henry Hub prices and WTI prices, respectively. The actual prices realized from the sale of natural gas and oil differ from the quoted NYMEX Henry Hub and WTI prices as a result of location differentials. Location differentials to NYMEX Henry Hub and WTI prices, also known as basis differential, result from variances in regional natural gas and oil prices as compared to NYMEX Henry Hub and WTI prices due to regional supply and demand factors. We have experienced, and expect to continue to experience, differentials to NYMEX Henry Hub and WTI prices, which may be material and could reduce the price we receive for these products relative to these benchmarks.

Lower commodity prices and negative increases in our differentials have reduced, and we expect will continue to reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, or at all, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices and negative differentials have also caused a significant portion of our development and exploration projects to become uneconomic, which may result in our having to make significant downward adjustments to our reserves. As a result, if commodity prices continue to remain depressed for a lengthy period of time or experience a further substantial or extended decline, or if our negative differentials increase, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures may be materially adversely affected.

Commodity prices have declined substantially from historic highs and may remain depressed for the foreseeable future. If commodity prices continue to remain depressed, we may be required to write down the value of our oil and natural gas properties, some of our undeveloped locations may no longer be economically viable and the value of our estimated proved reserves could be reduced materially.

During the eight years prior to December 31, 2017, natural gas prices at Henry Hub have ranged from a high of \$8.15 per MMBtu in 2014 to a low of \$1.49 per MMBtu in 2016. On December 31, 2017, the Henry Hub spot market price of natural gas was \$3.69 per MMBtu. The reduction in prices has been caused by many factors, including increases in natural gas production and reserves from unconventional (shale) reservoirs, without an offsetting increase in demand. In addition, oil prices have declined significantly since the second half of 2014. The price of WTI crude oil was \$60.46 per barrel on December 31, 2017, which is a significant decline from \$106.07 per barrel on June 30, 2014. This environment could cause the commodity prices for oil and natural gas to remain at currently depressed levels or to fall to lower levels. If commodity prices remain depressed for lengthy periods, we may be required to write down the value of our oil and natural gas properties, and some of our undeveloped locations may no longer be economically viable. For example, for the year ended December 31, 2017, we recorded an impairment charge on certain oil and gas properties located in Ohio of \$28.3 million for unproved properties, primarily attributable to lower commodity prices, and we have recorded impairment charges in prior years for similar reasons. In addition, sustained low commodity prices will negatively impact the value of our estimated proved reserves, which will negatively affect the borrowing base under our revolving credit facility and reduce the amounts of cash we would otherwise have available to pay expenses and service any indebtedness that we may incur. In such a case, we may be required to sell assets or raise capital by issuing additional debt or equity in order pay expenses and service indebtedness. Furthermore, the value of our assets, if sold, may not be sufficient to pay our expenses or service our indebtedness.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. For example, for the year ended December 31, 2017, we recorded an impairment charge on certain oil and gas properties located in Ohio of \$28.3 million for unproved properties, primarily attributable to lower commodity prices, and we have recorded impairment charges in prior years for similar reasons. Based on specific market factors and

circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to further write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

If commodity prices do not improve or worsen or if we are unable to increase our liquidity, we could experience ratings downgrades.

If commodity prices do not improve or worsen or if we are unable to increase our liquidity, we could experience ratings downgrades. For example, in January 2016, Moody's downgraded our corporate family credit rating and the rating of our 8.875% senior unsecured notes due 2023 primarily due to the effect of high leverage, low natural gas prices and significant production curtailments on our ability to generate cash flow from operations. These ratings were subsequently upgraded by Moody's in July 2017. In the event of any future downgrade, certain of our service providers, including our pipeline providers, may require us to post collateral or provide other assurances of our ability to perform our obligations under our contracts with such providers, which would negatively affect our liquidity and the borrowing base under our revolving credit facility and, in turn, increase the risk of additional downgrades.

Our development and exploration projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We have made, and if commodity prices rebound, expect to continue to make, substantial capital expenditures for the development and acquisition of oil and natural gas reserves. We expect to fund our capital expenditures in 2018 and subsequent to 2018 with cash on hand, cash generated by our operations and financing activities, which may include borrowings under our revolving credit facility, proceeds from non-core asset sales, proceeds from our drilling joint venture, and issuances of debt or equity. If we do not have sufficient borrowing availability under our revolving credit facility due to the current commodity price environment or otherwise, we may seek alternate debt or equity financing options (including, subject to compliance with our debt agreements, the issuance of first lien notes or other priority lien obligations), to sell assets or to further reduce our capital expenditures. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas, NGLs and oil prices and differentials, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in realized natural gas, NGLs or oil prices from current levels has resulted in a decrease in our actual capital expenditures, which have negatively impacted, and may continue to negatively impact, our ability to grow production. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flows from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions.

Our cash flows from operations and access to capital are subject to a number of variables, including, without limitation, the following:

- our proved reserves;
- the volumes and types of hydrocarbons we are able to produce from existing and future wells;
- our access to, and the cost of accessing, end markets for our production;
- the prices at which our production is sold;
- our ability to acquire, locate and develop new reserves;
- the levels of our operating expenses; and
- our ability to borrow under our revolving credit facility and issue additional debt and equity securities.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower natural gas, NGLs or oil prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If our cash on hand, cash flows generated by

our operations and available borrowings under our revolving credit facility are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a further curtailment of our operations

relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

Changes in laws or government regulations regarding hydraulic fracturing could increase our costs of doing business, limit the areas in which we can operate and reduce our oil and natural gas production, which could adversely impact our business.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and additives under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. However, with increased public concern regarding the potential for hydraulic fracturing to adversely affect drinking water supplies or other environmental impacts, proposals have been made, and in many cases finalized, to enact federal, state and local legislation and regulations that would increase, or have increased, the regulatory burden imposed on hydraulic fracturing. For example, the U.S. Environmental Protection Agency (the “EPA”) issued regulations to control air emissions from oil and natural gas production and natural gas processing operations, then proposed and finalized additional air emissions regulations from oil and natural gas production and natural gas processing operations, completed a multi-year study examining the potential impacts of hydraulic fracturing on drinking water resources, established standards for wastewater discharges from oil and gas extraction activities and released an Advance Notice of Proposed Rulemaking to solicit public comment on potential chemical disclosure requirements. The U.S. Congress continues to consider amending the Safe Drinking Water Act to remove the exemption for hydraulic fracturing activities and to require disclosure of additives constituents of fluids used in the fracturing process. The Department of the Interior released final rules to regulate hydraulic fracturing activities on federal lands and to limit venting and flaring from production operations. Although the hydraulic fracturing rules have been rescinded and the venting and flaring rule has been delayed, both are the subject of litigation that could result in such rules becoming effective and it is possible that replacement or similar rules will be proposed and finalized. In addition, the United States has made commitments to reduce greenhouse gas emissions under the Paris Agreement, part of the United Nations Framework Convention on Climate Change, and President Obama and Prime Minister Trudeau of Canada announced a joint agreement to reduce methane emissions from existing oil and gas operations. The Trump administration has since notified the United Nations of its intent to withdraw from the Paris Agreement, but under the terms of the agreement the U.S. will remain a party until approximately August 2020.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for us to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce our oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Properties that we decide to drill may not yield natural gas, NGLs or oil in commercially viable quantities.

Properties that we decide to drill that do not yield natural gas, NGLs or oil in commercially viable quantities will adversely affect our results of operations and financial condition. Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. If the wells in the process of being drilled and completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected. In addition, there is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs or oil in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas, NGLs or oil will be present or, if present, whether natural gas, NGLs or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

Hydrocarbon windows, phases or type curve areas have an inherent degree of variability and may change over time, and as a result, the available well data with respect to such windows, phases and type curve areas may not be indicative of the actual hydrocarbon composition for the windows, phases or type curve areas.

Based upon the well data available to us, we have grouped the publicly disclosed Utica Shale wells within the Utica Core Area into several distinct hydrocarbon windows, phases or type curve areas in an effort to better understand the thermal maturation variability within the Utica Core Area. However, there is an inherent degree of variability within such hydrocarbon windows, phases or type curve areas. Additionally, the well data we have utilized is predominantly based upon initial production rate, Btu content, natural gas yields and condensate yields, which may change over time. As a result, the well data with respect to the windows, phases and type curve areas within the Utica Core Area may not be indicative of the actual hydrocarbon composition for the windows, phases or type curve areas, or may not be the hydrocarbon composition of the windows, phases or type curve areas at the time we drill. Due to such factors, the performance, Btu content and NGLs and/or condensate yields of our wells may be substantially less than we anticipate or substantially less than performance and yields of other operators in the Utica Core Area, which may materially adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

We have been an early entrant into the Utica Core Area, which is an emerging play, and have also been an early entrant into the portion of the Marcellus Shale underlying our Marcellus Area. As a result, our expected well results in these areas are uncertain, and the value of our undeveloped acreage will decline if well results are unsuccessful.

Our expected well results in the Utica Core Area and our Marcellus Area are more uncertain than well results in areas that are more developed and have a greater number of producing wells. As a result, our cost of drilling, completing and operating wells in the Utica Core Area and our Marcellus Area may be higher than initially expected, the ultimate production and reserves from these wells may be lower than initially expected and the value of our undeveloped

acreage may decline. Additionally, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. We cannot assure you that unproved property acquired by us or

undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us, other oil and gas exploration and production companies and our service providers. Risks that we face while drilling include, but are not limited to, the following:

- drilling wells that are significantly longer and/or deeper than more conventional wells;
 - standing our wellbore in the desired drilling zone;
 - staying in the desired drilling zone while drilling horizontally through the formation;
 - running our casing the entire length of the wellbore; and
 - being able to run tools and other equipment consistently through the horizontal wellbore.
- Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Drilling for and producing natural gas, NGLs and oil are high-risk activities with many uncertainties that could result in a total loss of investment or otherwise adversely affect our business, financial condition and results of operations.

Our future financial condition and results of operations will depend on the success of our development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable production or that we will not recover all or any portion of our investment in such wells.

Our decisions to purchase, explore or develop prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “Items 1 and 2. Business and Properties—Oil and Natural Gas Data.” Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could materially reduce our borrowing capacity. In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including, without limitation, the following:

- compliance with regulatory requirements, including limitations resulting from wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering and processing facilities or delays in construction of gathering and processing facilities;

- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as blizzards and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- terrorist (including eco-terrorist) attacks targeting natural gas and oil related facilities and infrastructure;
- declines in natural gas, NGLs and oil prices;
- limited availability of financing at acceptable terms;
- title problems and well permit objections from coal operators; and
- limitations in the market for natural gas.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

We have incurred losses from operations in nearly every year since our inception and may do so in the future.

Although we generated net income of \$8.5 million for the year ended December 31, 2017, we incurred a net loss in each of the prior years since our inception. Our development of and participation in a large number of prospects has required, and if commodity prices rebound will require, substantial capital expenditures. The uncertainty and factors described throughout this “Risk Factors” section may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future, which could adversely affect the trading price of our common stock and our ability to fund our operations and fulfill our debt obligations.

We may not be able to generate sufficient cash to service all of our indebtedness, including our senior unsecured notes, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our senior unsecured notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal of, or premium, if any, and interest on, our indebtedness when due.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, raise additional capital or restructure or refinance our indebtedness. Our ability to raise additional capital or restructure or refinance our indebtedness will depend on the condition of the credit, financial or other capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with covenants that could further restrict our business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness.

In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. The value of our assets, particularly in times of low or volatile commodity prices, may not be sufficient to satisfy our liquidity needs or to repay our indebtedness. Furthermore, the credit agreement governing our revolving credit

facility and the indenture governing our senior unsecured notes restrict our subsidiaries' ability to dispose of assets and our subsidiaries' use of the proceeds from any such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations and fund our operations.

As of December 31, 2017, we had approximately \$510.5 million in total indebtedness, no senior secured indebtedness outstanding and approximately \$191.4 million of available borrowing capacity under our revolving credit facility (after giving effect to approximately \$33.6 million of outstanding letters of credit). Subsequent to December 31, 2017, we borrowed \$45 million under our revolving credit facility, which reduced the available borrowing capacity under such facility to \$146.4 million.

In the future, we may not be able to access adequate funding under our revolving credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination, unwillingness of the lenders to increase their aggregate commitment up to an increased borrowing base amount or an unwillingness or inability on the part of one or more lenders to meet their funding obligations and the inability of other lenders to provide additional funding to cover each unwilling or defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future, and in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Our producing properties are concentrated in the Appalachian Basin, which makes us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Appalachian Basin. At December 31, 2017, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, weather related conditions or interruption of the processing or transportation of natural gas, NGLs or oil. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations. In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations, the existence of which could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. These restrictions on our operations, and any similar restrictions, can cause delays or interruptions or can prevent us from executing our business strategy, which could have a material adverse effect on our financial condition and results of operations.

Due to the concentrated nature of our portfolio of natural gas and oil properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

We own non-operating interests in properties developed and operated by third parties, and as a result, we are unable to control the operation and profitability of such properties.

We frequently participate as a non-operator in the drilling and completion of wells with third parties that exercise exclusive control over such operations. As a non-operator participant, we rely on the third party operating company to successfully operate these properties pursuant to joint operating agreements and other similar contractual arrangements.

As a non-operator participant in these operations, we may not be able to maximize the value associated with these properties in the manner we believe appropriate, or at all. For example, we cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third party operator's operational expertise and financial

resources and ability to gain the approval of other participants in drilling wells will impact the timing and potential success of our drilling and development activities in a manner that we are unable to control. 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 favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

Our existing providers of gas gathering, processing and fractionation capacity may not be able to provide to us sufficient capacity for our production from the Utica Core Area, and as a result, we may be required to find alternative markets and gathering, processing or fractionation arrangements for our production from the Utica Core Area, which alternative arrangements may not be available on favorable terms, or at all.

A significant portion of our Utica Core Area acreage position is dedicated to long-term firm gas gathering, processing and fractionation agreements with primary terms of approximately 15 years. These agreements give us priority service and capacity over non-firm parties that wish to utilize the gas processing and fractionation plants and gas gathering system. As a result of such dedications, a significant portion of our operated wet gas acreage is committed to Blue Racer for gathering, processing and fractionation. Additionally, a significant portion of our operated dry gas acreage is committed to Eureka Midstream for gathering and a significant portion of our operated wet gas acreage is committed to EnLink Midstream for condensate gathering and stabilization. While we believe we have reserved sufficient capacity at these plants and on such systems to gather, process, fractionate and stabilize all of our projected production associated with our proved resources and a significant portion of our projected production from the Utica Core Area, that capacity may not be sufficient to handle all of our production or that the plants and systems will not experience significant mechanical problems or delays in construction or become unavailable to us due to unforeseen circumstances. As a result, we may be required to find alternative markets and gathering, processing or fractionation arrangements for our production from the Utica Core Area that is committed under these agreements, and such alternative arrangements may only be available on less favorable terms, or not at all.

We currently do not have agreements with providers of gas gathering, processing or fractionation capacity with respect to our production from our Marcellus Area, and we may not be able to enter into such agreements on favorable terms, or at all.

We have not entered into any gas gathering, processing or fractionation agreements with respect to our production from our Marcellus Area. We may not be able to enter into any such agreements on favorable terms, or at all. Without such agreements, we may not receive priority service or capacity over third parties that utilize the same gas processing and fractionation plants and gas gathering systems. Our inability to obtain sufficient gas gathering, processing and fractionation capacity for our production from our Marcellus Area could negatively impact our cash flows, financial condition and results of operations and reduce the overall value of our assets within this area.

Insufficient processing or takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas, NGLs and oil prices.

The Appalachian Basin natural gas business environment has historically been characterized by periods in which production has surpassed local processing and takeaway capacity, resulting in substantial discounts in the price received by producers such as us. A significant portion of our production from the Utica Core Area is currently being transported on pipelines that, after including the cost of such transportation, will consistently or periodically experience a negative differential to NYMEX Henry Hub prices.

Significant portions of our contracted firm transportation capacity have not been put into service. To the extent such projects are delayed or cancelled and we are unable to secure additional long-term firm takeaway capacity on major

pipelines that are in existence or currently under construction in our core operating area to accommodate our production and to manage basis differentials, it could have a material adverse effect on our financial condition and results of operations.

Oil and condensate produced in the Appalachian Basin has increased substantially. There is limited takeaway capacity for these products and our sales of these products are currently occurring, and we expect will continue to

occur, at a discount to the benchmark WTI price. If our providers are unable to secure buyers for these products, it could have a material adverse effect on our financial condition and results of operations.

We currently are and in the future expect to be party to contracts with third parties that include contractual minimums.

We are currently party to and expect to continue to be party to service contracts with drilling rig companies that require us to make shortfall payments to such companies if our actual activity level falls below specified contractual minimum activity levels. Moreover, we have entered into service contracts, and in the future may enter into additional service contracts, such as firm pipeline transportation contracts with companies owning interstate pipelines, that require us or may require us to make shortfall payments if our actual throughput falls below specified contractual minimum volumes. For the year ended December 31, 2017, we incurred approximately \$0.8 million in shortfall payments under such contracts. Additionally, in 2018, we expect to have additional firm transportation capacity come into service that we do not currently anticipate filling, which may require us to make shortfall payments if we cannot otherwise optimize or sell such capacity. As such, we can provide no assurance that our activity levels will be sufficient to satisfy the minimum requirements under our drilling rig contracts or that our future volumes will be sufficient to satisfy the minimum requirements under any such firm transportation contracts. If we fail to satisfy the minimum activity levels or throughput requirements associated with such contracts, we would be obligated to make shortfall payments to our counterparties based on the difference between our actual activity levels and throughput volumes, respectively, and the contract minimums in each case. These differences and the associated shortfall payments could be significant and we may not be able to generate sufficient cash to cover those obligations, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

The credit agreement governing our revolving credit facility contains a number of significant covenants, including restrictive covenants that restrict our and our subsidiaries' ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- hedge future production;
- incur liens;
- change the nature of our business; and
- engage in certain other transactions without the prior consent of the lenders.

The indenture governing our senior unsecured notes contains similar restrictive covenants. In addition, the credit agreement governing our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indenture governing our senior unsecured notes, may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants of the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes.

A breach of any covenant in the credit agreement governing our revolving credit facility or the indenture governing our senior unsecured notes would result in a default under the applicable agreement after any applicable grace periods.

A default, if not waived or cured, could result in acceleration of the indebtedness outstanding under

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the relevant agreement and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or obtain sufficient capital to refinance such indebtedness. Even if a refinancing were available, it may not be on terms that are acceptable to us. Moreover, an increased interest rate is also payable in connection with a default under the credit agreement governing our revolving credit facility and certain payment defaults under the indenture governing our senior unsecured notes.

Any significant reduction in our borrowing base or reduction of lender commitments under our revolving credit facility, as a result of the periodic borrowing base redeterminations or otherwise, may negatively impact our ability to fund our capital expenditure plan.

We expect to fund a portion of our capital expenditure plan through 2018 with future borrowings under our revolving credit facility. The credit agreement governing our revolving credit facility limits the amounts we can borrow under our revolving credit facility from time to time up to a specified maximum borrowing base amount or the aggregate amount of lender commitments, whichever is less. The lenders, in their sole discretion, will determine a borrowing base on a semi-annual basis based upon the loan value assigned to the proved reserves attributable to our oil and gas properties evaluated in our most recent reserve report(s). Our lenders may further request two additional unscheduled borrowing base redeterminations during each calendar year. Any increase in the borrowing base will require the consent of the lenders holding 95.0% (or 100.0% if there are fewer than three lenders at the time of determination) of the outstanding credit amounts, or if none are then outstanding, 95% of the commitments (provided that no lender's commitment may increase without its consent). Distinct from determinations of a borrowing base, each lender, in its sole discretion, will determine the maximum amount of loans it will commit to make under our revolving credit facility based, in part, on general economic considerations and its prevailing lending policies. Outstanding borrowings in excess of the lesser of the specified maximum borrowing base amount or the prevailing aggregate lender commitment must be repaid. If we fail to repay such excess borrowings on a timely basis, we must provide additional oil and gas properties as collateral to the extent necessary to eliminate the deficiency. As of December 31, 2017, the borrowing base under our revolving credit facility was \$225 million and there were no outstanding borrowings under our revolving credit facility, resulting in borrowing availability of approximately \$191.4 million (after giving effect to approximately \$33.6 million of outstanding letters of credit). Subsequent to December 31, 2017, we borrowed \$45 million under our revolving credit facility, which reduced the available borrowing capacity under such facility to \$146.4 million.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

We have made asset and business acquisitions in the past, including, most recently, the Flat Castle Acquisition, and we may continue to make acquisitions of assets or businesses in the future that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Further, the success of any completed acquisition, including the Flat Castle Acquisition, depends on our ability to integrate the acquired business effectively into our existing operations and such integration process may involve difficulties that require a disproportionate amount of our managerial and financial resources to resolve. We may also fail to realize the expected benefits of any completed acquisitions, and completed acquisitions may subject us to significant transaction costs, unknown liabilities, and/or other unanticipated expenses, such as litigation expenses.

In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate successfully the acquired businesses and

assets into our existing operations or to minimize any unforeseen liabilities or operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes impose certain limitations on our ability to enter into mergers or combination transactions and to make investments. The credit agreement governing our revolving credit facility and the indenture governing

our senior unsecured notes also limit our ability to incur certain indebtedness and liens, which could limit our ability to engage in acquisitions of businesses.

We may be subject to risks in connection with acquisitions of properties.

We have historically acquired assets and businesses that we feel complement our assets and business and may continue to do so in the future. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
 - future natural gas, NGLs or oil prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including, without limitation, assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. As a substantial portion of our reserve estimates are made without the benefit of a lengthy production history, any significant variance from the above assumption could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Reserve estimates for plays, such as the Utica Core Area and our Marcellus Area, where we predominately operate, that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. Less production history may contribute to less accurate estimates of reserves, future production rates and the timing of development expenditures. Most of our production is from wells that have been operational for less than one year, and as estimated reserves vary substantially from well to well, estimated reserves may not be

correlated to perforated lateral length or completion technique. Furthermore, the lack of operational history for horizontal wells in the Utica Core Area and our Marcellus Area may also contribute to the inaccuracy of future estimates of reserves and could result in our failing to achieve expected results in these plays. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates or management expectations would have a material adverse effect on our business, financial condition, results of operations and cash flows. Furthermore, given the amount of our total estimated proved reserves in relation to the amount of our outstanding debt obligations, the value of our assets may not be sufficient to satisfy our liquidity needs or to repay our indebtedness.

Our gross identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the capital that we expect to be necessary to drill our identified drilling locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas, NGLs and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, topographical constraints, lease expirations, the ability to form units, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, governmental regulation, the ability to pool or unitize our acreage with acreage leased to other operators and approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other identified drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. Further, some of the horizontal wells we intend to drill in the future may require unitization with adjacent leaseholds controlled by third parties. If these third parties are unwilling to unitize such leaseholds with ours, this may limit the total locations we can drill. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2017 after deducting wells that have been drilled or are in progress, we had identified approximately 98.2, 18.3, 93.8, and 78.1 net undeveloped Dry Gas, Rich Gas, Condensate and Marcellus Condensate locations, respectively. As a result of the limitations described above, including the recent significant declines in natural gas and oil prices, we may be unable to drill many of our identified drilling locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified drilling locations, see “Business—Our Properties.”

We have acreage that we must commence operations upon before lease expiration in order to hold the acreage by production. If we fail to drill sufficient wells to hold acreage we incur substantial lease renewal costs, or if renewal is not feasible, lose our lease and prospective drilling opportunities.

Leases on our oil and natural gas properties typically have a primary term of 5 years, after which they expire unless, prior to expiration, we commence operations within the spacing units covering the undeveloped acres. As of December 31, 2017, we had leases representing approximately 33,069 gross (21,473 net) undeveloped acres scheduled to expire in 2018, 12,339 gross (9,760 net) undeveloped acres scheduled to expire in 2019, 3,320 gross (2,657 net) undeveloped acres scheduled to expire in 2020, 14,570 gross (11,919 net) undeveloped acres scheduled to expire in 2021, and 14,657 gross (11,685 net) undeveloped acres scheduled to expire in 2022 and beyond. The cost to renew

such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms, or at all. Moreover, many of our leases require lessor consent to create units larger than the leases currently permit, which may make it more difficult to hold our leases by production or optimally develop our leasehold position. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas, NGLs and oil prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment,

gathering systems and pipeline transportation constraints and regulatory approvals. In order to hold our current leases that are scheduled to expire in 2018 and 2019, we have deployed a strategy to convert our land extension payments into multi-year delay rental payments, which is designed to spread the costs beyond a single year. We cannot assure you that we will have the liquidity to execute on this strategy, that landowners will be willing to enter into this type of lease modification or that we will have the liquidity to otherwise deploy rigs when needed to hold this expiring acreage. Our reserves and future production, and therefore, our future cash flows and income, are highly dependent on successfully extending or developing our undeveloped leasehold acreage and the loss of any leases could materially adversely affect our ability to so develop such acreage.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2015, December 31, 2016 and December 31, 2017, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas average prices without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for natural gas, NGLs and oil;
- actual cost of development and production expenditures;
- the effect of derivative transactions;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure 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 natural gas industry in general. As a corporation, we are treated as a taxable entity for federal income tax purposes, and our income taxes are dependent on our taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report which could have a material effect on the value of our reserves.

We may incur losses as a result of title defects in the properties in which we invest.

Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due to the long history of land ownership in the area, resulting in extensive and complex chains of title. In the course of acquiring the rights to develop oil and natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment subject to title verification. In most cases, we incur the expense of retaining lawyers, title abstractors or landmen to verify the rightful owners of the oil and gas interests prior to payment of such lease bonus to the lessor. There is no certainty, however, that a lessor has valid title to its lease's oil and gas interests. In those cases, such leases are generally voided and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Accordingly, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an

interest, we could suffer a financial loss or an impairment of our assets.

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The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2017, we had 1,458.6 Bcfe of total estimated proved reserves, of which approximately 69% were classified as proved undeveloped. Our approximately 1,002.6 Bcfe of estimated proved undeveloped reserves will require an estimated \$835.2 million of development capital over the next 5 years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we successfully conduct ongoing development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future oil and natural gas reserves and production, and therefore our future cash flows and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Conservation measures and technological advances could reduce demand for natural gas, NGLs and oil.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to natural gas, NGLs and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas, NGLs and oil. The impact of the changing demand for natural gas, NGLs and oil services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas and oil, we have entered into derivative instrument contracts for a significant portion of our natural gas, NGLs and oil production, including fixed-price swaps, basis swaps, collars and firm sales agreements. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse

to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. Any default by a counterparty to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables (\$23.2 million at December 31, 2017) and the sale of our natural gas and oil production (\$52.9 million in receivables at December 31, 2017). Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells. For the year ended December 31, 2017, two customers, Emera Energy Services and Marathon, accounted for approximately 17% and 10%, respectively, of our revenues. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our operating history is limited and as a result there is only limited historical financial and operating information available upon which to base an evaluation of our performance. Moreover, the historical financial and operating information included in this Annual Report may not be indicative of our future financial performance.

Our operating history is limited and as a result there is only limited historical financial and operating information available upon which to base an evaluation of our performance. Moreover, the historical financial and operating information included in this Annual Report may not be indicative of our future financial performance. We have yet to generate positive earnings from our current business strategy and there can be no assurance that we will ever operate profitably. If our current business strategy is not successful, and we are not able to operate profitably, investors may lose some or all of their investment.

Our operations are subject to governmental laws and regulations, which may expose us to significant costs and liabilities that could exceed current expectations.

Our operations are subject to various federal, state and local governmental regulations. Matters subject to regulation include wastewater disposal, the spacing of wells, unitization and pooling of properties and taxation. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations, primarily relating to protection of human health and the environment. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue for the foreseeable future. Please read "Items 1 and 2. Business and Properties—Regulation of the Oil and Natural Gas Industry" and "Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters" for a description of

the laws and regulations that affect us.

We make assumptions and develop expectations about possible expenditures based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, new capital costs may be incurred to

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comply with such changes. In addition, new laws and regulations might adversely affect our operations and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions.

Recent decisions by the Ohio Supreme Court interpreting the Ohio Dormant Mineral Act relating to preservation of mineral rights by surface owners could complicate title review, delay drilling activities and increase leasehold expenses with respect to some of our leasehold acreage in Ohio.

On September 15, 2016, the Ohio Supreme Court issued a series of decisions relating to the Ohio Dormant Mineral Act, which we refer to as the ODMA. In the lead case, *Corban v. Chesapeake Exploration L.L.C.*, the court concluded that the 1989 version of the ODMA did not transfer ownership of dormant mineral rights automatically, by operation of law. Instead, prior to 2006, surface owners were required to bring a quiet title action in order to establish abandonment of mineral rights. After June 30, 2006 (the effective date of the 2006 version of the ODMA), surface owners are required to follow the statutory notice and recording procedures enacted in 2006. As a result, going forward, it will be more difficult for a surface owner to achieve an abandonment of mineral rights as the Ohio Supreme Court held that the statutory notice and recording provisions of the 2006 version of the ODMA will apply. In addition, mineral interests that may previously have been believed to be automatically abandoned by operation of law will now be valid pursuant to the Ohio Supreme Court's rulings. Accordingly, these recent Ohio Supreme Court decisions may complicate title review, delay drilling activities and increase leasehold expenses with respect to our operations in Ohio where the majority of our acreage and producing properties are located, any of which could have an adverse effect on our results of operations and financial condition.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several strict liability may be incurred without regard to fault under some environmental laws and regulations, including the Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act, the Oil Pollution Act, and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas, oil and wastes on, under, or from our properties and facilities. Private parties may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate may be located near current or former third party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

We may be held responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water and water disposal options. Restrictions on the ability to obtain water or dispose of wastewater may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations.

In addition, various studies have identified potential links between increases in seismic activity and the injection/disposal of water associated with oil and natural gas production, which could result in the imposition of operational limits or closure of disposal wells in areas where such links are suspected. For example, the Ohio Department of Natural Resources (“ODNR”) adopted rules that, among other things, allows the ODNR to require submission of a seismic monitoring plan, and requires continuous monitoring of injection and annulus pressures on new wells.

We are subject to risks associated with climate change.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases (“GHGs”). The EPA has issued a series of GHG monitoring, reporting and emissions control rules for oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG, cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce GHG emissions and in March 2016 President Obama and Prime Minister Trudeau of Canada announced a joint agreement to reduce methane emissions from existing oil and gas operations. Our business and our financial results could be adversely impacted to the extent that the United States implements any additional GHG regulations in accordance with such agreement. The Trump administration has since notified the United Nations of its intent to withdraw from the Paris Agreement, but under the terms of the agreement the U.S. will remain a party until approximately August 2020.

The costs that may be associated with the impacts of climate change and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, and the demand for and consumption of our products and services (due to changes in both costs and weather patterns). 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. At this time, however, it is not possible to estimate how future laws or regulations or climatic changes may impact our business.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline or river contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines or processing facilities;
- personal injuries and death;
- natural disasters; and
- terrorist (including eco-terrorist) attacks targeting natural gas and oil related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

injury or loss of life;

damage to and destruction of property, natural resources and equipment;

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- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

In accordance with what we believe to be customary industry practice, we maintain insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any or all of the losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flows. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial condition. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are a large part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and cleanup costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the “occurrence” to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows.

Market conditions or operational impediments may hinder our access to natural gas, NGLs or oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas, NGLs or oil transportation arrangements may hinder our access to markets or delay our production. The availability of a ready market for our production depends on a number of factors, including the demand for and supply of natural gas, NGLs or oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Because many of our operations are in an emerging play, much of this infrastructure is currently being built or is yet to be built, and we cannot assure you that it will be built on time or at all. Our failure to obtain such services on acceptable terms and concurrent with the completion of our wells could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs or oil pipeline or gathering system capacity. In addition, if quality specifications for the third party pipelines with which we connect change so as to restrict our ability to transport product, our access to markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Some of the rigs performing work for us do so on a well-by-well basis and can refuse to provide such services at the conclusion of drilling on the current well. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and

equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas, NGLs and oil and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas and oil properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The past success of our senior management with developing public natural gas and oil enterprises, and the expertise of our senior management in the acquisition, exploration and development of unconventional natural gas and oil properties does not guarantee our success or profitability.

As described in this Annual Report, most of our executive officers and other key personnel, including our Chairman, President and Chief Executive Officer, Benjamin W. Hulburt, our Executive Vice President, Corporate Development and Geosciences, Thomas S. Liberatore, our Executive Vice President and Chief Operating Officer, Oleg Tolmachev, and our Executive Vice President, Secretary and General Counsel, Christopher K. Hulburt, have substantial past experience in the acquisition, exploration and development of unconventional natural gas and oil properties, including experience at Rex Energy Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation and Stone Energy Corporation. However, the past experience and success of our executive officers and other key personnel with respect to previous endeavors in the natural gas and oil industry is not a guarantee of our future success or profitability.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel, including Benjamin W. Hulburt, our Chairman, President and Chief Executive Officer, Matthew R. DeNezza, our Executive Vice President and Chief Financial Officer, Thomas Liberatore, our Executive Vice President, Corporate Development and Geosciences, Oleg Tolmachev, Executive Vice President and Chief Operating Officer, and Christopher K. Hulburt, our Executive Vice President, Secretary and General Counsel, could have a material adverse effect on our business, financial condition and results of operations.

Seasonal weather conditions and regulations intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in the areas where we operate.

Natural gas and oil operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect certain species of wildlife. For example, we must comply with state and federal regulations aimed at protecting the Indiana and Northern Long-Eared bats, which have been listed as a protected species by both federal and state law, and those regulations restrict or increase the cost of our operations by, among other things, limiting our ability to clear trees to establish rights of way or pad locations on some of our acreage during certain periods of the year. See “Items 1 and 2. Business and Properties—Regulation of Environmental and Occupational Safety and Health Matters—Endangered Species Act and Migratory Bird Treaty Act.” Adverse seasonal

weather conditions and wildlife regulations may limit our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. In addition, the designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, development and production activities.

Acts of terrorism (including eco-terrorism) could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and operations, and the assets and operations of our providers of gas gathering, processing, transportation and fractionation services, may be targets of terrorist activities (including eco-terrorist activities) that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport, market or distribute natural gas, NGLs and oil. Acts of terrorism, as well as events occurring in response to or in connection with acts of terrorism, could cause environmental and other repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, acts of terrorism, and the threat of such acts, could result in volatility in the prices for natural gas, NGLs and oil and could affect the markets for such commodities.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flows used for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially adversely affect our ability to achieve our planned growth and operating results.

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could adversely affect our ability to use derivative instruments to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) was enacted on July 21, 2010 and establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission (the “CFTC”) and the SEC to promulgate certain rules and regulations implementing the Dodd-Frank Act, with the CFTC responsible for the rules and regulations regarding derivatives of the type we may use to hedge certain risks. Although the CFTC has finalized most of its implementing regulations, others remain to be finalized and it is not possible at this time to predict when this will be accomplished. In addition, the CFTC and its staff regularly issue rule amendments and guidance, policy statements, and letters interpreting the derivatives provisions of the Dodd-Frank Act, the contents of which cannot be known in advance.

The Dodd-Frank Act enhanced the CFTC’s authority to establish rules and regulations setting position limits for certain futures and option contracts, including in the major energy markets, and, for the first time, swaps that are their economic equivalents. The CFTC’s initial position limits rules under the Dodd-Frank Act were vacated by the U.S. District Court for the District of Columbia in September 2012 before such rules took effect. However, the CFTC has proposed new rules that would place limits on positions in certain core futures, options and equivalent swaps contracts in certain physical commodities, subject to limited exceptions for certain bona fide hedging and other transactions. The CFTC has also adopted final rules regarding the aggregation of positions in determining compliance with federal position limits. While the position aggregation rules are final, the position limit rules themselves are not, and therefore the impact of those rules on our use of derivatives in commodities for which federal position limits would be imposed is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and execution on certain trading platforms. The CFTC has not yet proposed rules designating any other classes of swaps, including

physical commodity swaps, for mandatory clearing or trade execution. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, margin rules for uncleared swaps, adopted during the fourth quarter of 2016 by the CFTC and federal banking regulators and requiring the posting of collateral by swap dealers and certain other financial entities, could impact liquidity and therefore reduce our ability to execute hedges to reduce risk and protect cash flows. The margin

rules are not yet in effect for all market participants, and therefore the impact of those provisions to us is uncertain at this time.

The Dodd-Frank Act and regulations may have other effects, including requiring or causing the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives 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, which, among other impacts, could adversely affect our ability to plan for and fund capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and physically settled instruments related to oil and natural gas. Our revenues could therefore be adversely affected to the extent that the Dodd-Frank Act and regulations contribute to lower commodity prices.

Any of these consequences could have a material adverse effect on us, our financial condition or our results of operations.

Proposed changes to U.S. and state tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

Certain states may impose new or increased taxes or fees on natural gas and oil extraction. For example, Ohio has previously considered, and, the Ohio Legislature continues to consider proposals to increase the current severance tax imposed on production of natural gas or oil in Ohio. Pennsylvania historically has not imposed a severance tax on the production of natural gas. However, Pennsylvania's governor and legislature have continued to discuss the imposition of a state severance tax on the extraction of natural resources, including natural gas produced from the Marcellus, Upper Devonian, and Utica Shale formations, either in replacement of or in addition to the existing impact fee. If any legislation increasing severance taxes is enacted, or other similar changes that tax our production or reduce or eliminate deductions currently available with respect to natural gas and oil exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

Changes to state tax laws in response to recently enacted U.S. federal tax legislation or to impose new or increased taxes or fees on natural gas and oil extraction may result in an increase in the state taxes we pay.

Currently, many states conform their calculation of corporate taxable income to the calculation of corporate taxable income at the U.S. federal level. Due to recently enacted changes to U.S. federal income tax laws, certain states may change or modify the calculation of corporate taxable income at the state level. Any resulting increase in cost due to such changes could have an adverse effect on our financial position, results of operations and cash flows.

Future regulations relating to and interpretations of recently enacted U.S. federal income tax legislation may vary from our current interpretation of such legislation.

The U.S. federal income tax legislation recently enacted in Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act, is highly complex and subject to interpretation. The presentation of our financial condition and results of operations is based upon our current interpretation of the provisions contained in the Tax Cuts and Jobs Act. In the future, the Treasury Department and the Internal Revenue Service are expected to release regulations relating to and interpretive guidance of the legislation contained in the Tax Cuts and Jobs Act. Any significant

variance of our current interpretation of such legislation from any future regulations or interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

Risks Related to Our Common Stock

The price of our common stock has historically been volatile, and this volatility may affect the price at which you could sell your common stock.

Our common stock began trading on the New York Stock Exchange (“NYSE”) on June 20, 2014 and since such date the market price of our common stock has ranged from a low of \$0.65 per share in February 2016 to a high of \$27.18 per share in June 2014. This volatility may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could continue to fluctuate significantly for various reasons, including:

- general market conditions, including fluctuations in commodity prices;
- our operating and financial performance and drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- the public reaction to our press releases, our other public announcements and our filings with the SEC;
- strategic actions by our competitors;
- our failure to meet revenue, reserves or earnings estimates;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our common stock;
- sales of our common stock by us, certain investment funds (the “EnCap Funds”) managed by EnCap Investments L.P. (“EnCap”) or other stockholders, or the perception that such sales may occur;
- changes in accounting principles, policies, guidance, interpretations or standards;
- additions or departures of key management personnel;
- actions by our stockholders;
- domestic and international economic, legal and regulatory factors unrelated to our performance; and
- the realization of any risks describes under this “Risk Factors” section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company’s securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management’s attention and resources and harm our business, operating results and financial condition.

If we cannot meet the NYSE continued listing requirements, the NYSE may delist our common stock.

Our common stock is currently listed on the NYSE. In the future, if we are unable to meet the continued listing requirements of the NYSE, including, among other things, the requirement of maintaining a minimum average closing price of \$1.00 per share over a consecutive 30 trading-day period, we would fall below compliance standards and risk having our common stock delisted.

On February 26, 2016, we received a notice from the NYSE that that the average closing price of our common stock over a consecutive 30 trading-day period as of February 22, 2016 was below \$1.00 per share, and, as a result, the price per share of our common stock was below the minimum average closing price required to maintain listing on the

NYSE. However, on April 1, 2016, we received a subsequent letter from the NYSE confirming that our

average stock price per share over the consecutive 30 trading-day period as of March 31, 2016 was above the NYSE's minimum requirement of \$1.00, and that, as a result, we are no longer considered to be below the \$1.00 per share continued listing requirement.

In the event that we are once again notified by the NYSE that we have fallen below the minimum average closing price continued listing requirement, we intend to respond to the NYSE within 10 business days of our intent to cure such deficiency. We would have six months, or in certain circumstances, until we could take stockholder action at our next annual meeting, to regain compliance. During the cure period, our common stock would continue to be listed and traded on the NYSE, subject to compliance with the other NYSE continued listing standards.

A delisting of our common stock could negatively impact us by, among other things:

- reducing the liquidity and market price of our common stock;
- reducing the number of investors, including institutional investors, willing to hold or acquire our common stock, which could negatively impact our ability to raise equity;
- decreasing the amount of news and analyst coverage relating to us;
- limiting our ability to issue additional securities, obtain additional financing or pursue strategic restructuring, refinancing or other transactions; and
- impacting our reputation and, as a consequence, our ability to attract new business.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for, and rely on, exemptions from certain corporate governance requirements. As a result, our stockholders do not have the same protections afforded to stockholders of companies that are subject to such requirements.

The EnCap Funds beneficially own a majority of our common stock. We have entered into a stockholders' agreement with the EnCap Funds and certain other stockholders, pursuant to which such stockholders have certain rights relative to designated director nominees and agreed to vote their shares of common stock in accordance with the stockholders' agreement, including as it relates to the election of directors. As a result, we are a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of our board of directors consist of independent directors;
- we have a nominating and governance committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
 - we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

We are currently utilizing, and intend to continue to utilize, the exemption relating to the nominating and governance committee, and we may utilize this exemption for so long as we are a controlled company. Accordingly, our stockholders do not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

The EnCap Funds hold a substantial majority of our common stock.

The EnCap Funds, which are managed by EnCap, hold the majority of the outstanding shares of our common stock. EnCap is entitled to act separately in its own interest with respect to the shares of our common stock, and it has the voting power to elect all of the members of our board of directors and thereby control our management and affairs. In addition, EnCap has the ability to determine the outcome of all matters requiring stockholder approval, including mergers and other material transactions, and to cause or prevent a change in the composition of our board of directors or a change in control of our company that could deprive our stockholders of an opportunity to receive a premium for

their common stock as part of a sale of our company. The existence of a significant stockholder may

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also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as EnCap continues to control a significant amount of our common stock, it will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of EnCap may differ or conflict with the interests of our other stockholders. Moreover, this concentration of stock ownership may also adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder.

The stockholders' agreement we entered into in connection with the completion of our IPO permits certain stockholders to designate a majority of the members of our board of directors.

In connection with the completion of our IPO, we entered into a stockholders agreement with the EnCap Funds and certain other stockholders, pursuant to which such stockholders were provided with certain rights relative to designated director nominees and agreed to vote their shares of common stock in accordance with the stockholders agreement, including as it relates to the election of directors. Certain of our directors and members of our management team control or have other relationships with such stockholders.

Conflicts of interest could arise in the future between us, on the one hand, and EnCap and its affiliates, including its portfolio companies, on the other hand, concerning, among other things, acquisitions and divestitures, potential competitive business activities or business opportunities.

EnCap is a leading provider of private equity to the independent sector of the U.S. oil and gas industry and manages investment funds that own a majority of our common stock. From time to time, we may acquire assets from entities affiliated with EnCap, including its portfolio companies, such as the Flat Castle Acquisition, divest assets to such entities or otherwise transact business with such entities. For example, EnCap has an interest in Caiman Energy II, LLC, which owns a significant interest in Blue Racer, a provider of firm gathering, processing and fractionation capacity for our operated acreage in the Rich Gas, Condensate and Rich Condensate Windows of the Utica Core Area. As a result, EnCap's interests with respect to matters arising in connection with our arrangements with Blue Racer may not align with our interests. EnCap and its affiliates may also, from time to time, acquire interests in businesses that directly or indirectly compete with our business, or are significant existing or potential customers. EnCap and its affiliates may acquire or seek to acquire assets we seek to acquire, and as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Any actual or perceived conflicts of interest with respect to the foregoing could make us susceptible to litigation, which could result in substantial costs or divert our management's attention and resources or otherwise harm our business and adversely impact the trading price of our common stock.

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes—Oxley Act of 2002 (the "Sarbanes—Oxley Act"), may strain our resources, increase our costs and distract management.

We completed our IPO in June 2014. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. We also incur costs associated with our public company reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority. These rules and regulations have increased our legal and financial compliance costs and make some activities more time-consuming and costly. These rules and regulations also make it more difficult and more expensive for us to obtain director and officer

liability insurance. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

If we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our shares of common stock.

Future sales of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute our stockholders' ownership in us.

We may sell additional shares of common stock in subsequent public or private offerings. We may also issue additional shares of common stock or convertible securities. As of March 2, 2018, we had 301,770,671 outstanding shares of common stock. The EnCap Funds beneficially own an aggregate of 210,778,623 shares of our common stock, or approximately 70% of our total outstanding shares, of which approximately 44,662,273 shares have been registered with the SEC for resale. Upon the closing of the Flat Castle Acquisition, we entered into a registration rights agreement with Travis Peak Resources, LLC, pursuant to which we agreed to register the resale of an additional 37,823,596 shares of our common stock issued to Travis Peak Resources, LLC, an entity affiliated with EnCap, in the Flat Castle Acquisition. Subject to compliance with the Securities Act or exemptions therefrom, certain of our employees may sell their shares of common stock into the public market.

Subject to the satisfaction of vesting conditions and Rule 144 restrictions applicable to our affiliates, shares registered under our registration statement on Form S-8 filed on July 2, 2014 relating to our equity incentive plan are available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified board of directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;

providing that the board of directors is expressly authorized to adopt, or to alter or repeal our amended and restated bylaws; and
establishing advance notice and information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

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Our amended and restated certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.

Our amended and restated certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, or (iv) any action asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in shares of our common stock shall be deemed to have notice of and consented to the provisions of our amended and restated certificate of incorporation described above. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits against us and our directors, officers and other employees. Alternatively, if a court were to find these provisions of our amended and restated certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

We do not intend to pay cash dividends on our common stock, and the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare cash dividends on shares of our common stock in the foreseeable future. Additionally, the credit agreement governing our revolving credit facility and the indenture governing our senior unsecured notes place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

We are classified as an "emerging growth company" under the JOBS Act. For as long as we are an emerging growth company, which may be up to 5 full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act, (2) comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) provide certain disclosure regarding executive compensation required of larger public companies or (4) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to 5 years, following our initial public offering, although we will lose that status sooner if we have more than \$1.07 billion of revenues in a fiscal year, have more than \$700.0 million in market value of our common stock held by non-affiliates, or issue more than \$1.0 billion of non-convertible debt over a 3-year period.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our amended and restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to

elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of our common stock.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

Information regarding the Company's legal proceedings is set forth in "Note 13 —Commitments and Contingencies," located in the Notes to the Consolidated Financial Statements included in Part II Item 8. of this Annual Report and is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Common Stock

We have one class of common shares outstanding, having a par value of \$0.01 per share ("Common Stock"). Our Common Stock is traded on the New York Stock Exchange under the symbol "ECR". As of March 2, 2018, our Common Stock was held by 15 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange for the years ended December 31, 2016 and December 31, 2017.

	Sales Prices	
	High	Low
2016		
First Quarter	\$2.09	\$0.65
Second Quarter	\$4.42	\$1.32
Third Quarter	\$3.81	\$2.42
Fourth Quarter	\$3.66	\$2.32
2017		
First Quarter	\$2.81	\$2.03
Second Quarter	\$3.03	\$1.60
Third Quarter	\$3.10	\$2.06
Fourth Quarter	\$2.73	\$2.12

Dividend Policy

We have not paid any cash dividends since our inception, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the growth of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon then-existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, certain of our debt instruments place restrictions on our ability to pay cash dividends.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of \$100 on June 20, 2014, the first date on which our common stock was publicly traded, in each of our Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration & Production Index.

Item 6. Selected Financial Data

The following table shows the selected historical consolidated financial data of Eclipse Resources Corporation and subsidiaries for the periods and as of the dates indicated. Our historical results are not necessarily indicative of future operating results. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and related notes included in “Item 8. Financial Statements and Supplementary Data.”

Our historical results of operations also reflect a U.S. federal corporate tax rate of 35%. Effective January 1, 2018, the U.S. federal corporate tax rate was reduced from 35% to 21%. Accordingly, our historical results of operations reflect a higher U.S. federal corporate tax rate when compared to our future financial results.

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The selected historical consolidated financial data as of and for the years ended December 31, 2017, 2016, 2015, 2014 and 2013 are derived from the audited consolidated financial statements of Eclipse Resources Corporation.

Statement of Operations data: (in thousands)	Year Ended December 31,				
	2017	2016	2015	2014	2013
REVENUES					
Natural gas, oil and natural gas liquids sales	\$380,178	\$223,015	\$234,601	\$137,816	\$12,935
Brokered natural gas and marketing	3,481	12,019	20,720	—	—
Total revenues	383,659	235,034	255,321	137,816	12,935
OPERATING EXPENSES					
Lease operating	20,525	9,023	13,904	8,518	2,576
Transportation, gathering and compression	124,839	109,226	85,846	18,114	67
Production and ad valorem taxes	8,490	7,927	3,722	2,163	77
Brokered natural gas and marketing expense	3,191	12,268	26,173	—	—
Depreciation, depletion and amortization	118,818	92,948	244,750	89,218	6,163
Exploration	50,208	52,775	116,211	21,186	3,022
General and administrative	44,553	39,431	46,409	42,109	21,276
Rig termination and standby	1	3,846	9,672	3,283	—
Impairment of proved oil and gas properties	—	17,665	691,334	34,855	2,081
Accretion of asset retirement obligations	544	391	1,623	791	364
(Gain) loss on sale of assets	(179)	6,936	(4,737)	(960)	—
Gain on reduction of pension liability	—	—	—	(2,208)	—
Total operating expenses	370,990	352,436	1,234,907	217,069	35,626
OPERATING INCOME (LOSS)	12,669	(117,402)	(979,586)	(79,253)	(22,691)
OTHER INCOME (EXPENSE)					
Gain (loss) on derivative instruments	45,365	(52,338)	56,021	20,791	—
Interest expense, net	(49,490)	(50,789)	(53,400)	(48,347)	(20,850)
Gain (loss) on early extinguishment of debt	—	14,489	(59,392)	—	—
Other income (expense)	(19)	(149)	400	353	—
Total other expense, net	(4,144)	(88,787)	(56,371)	(27,203)	(20,850)
INCOME (LOSS) BEFORE INCOME TAXES	8,525	(206,189)	(1,035,957)	(106,456)	(43,541)
INCOME TAX BENEFIT (EXPENSE)	—	(546)	74,166	(73,519)	—
NET INCOME (LOSS)	\$8,525	\$ (206,735)	\$ (961,791)	\$ (179,975)	\$ (43,541)
NET INCOME (LOSS) PER COMMON					
SHARE					
Basic	\$0.03	\$ (0.86)	\$ (4.41)	\$ (1.25)	\$ (0.58)
Diluted	\$0.03	\$ (0.86)	\$ (4.41)	\$ (1.25)	\$ (0.58)
Statement of Cash Flow data:					
Net cash provided by (used in)					
Operating activities	\$112,746	\$6,405	\$80,299	\$8,513	\$12,438
Investing activities	(292,469)	(89,318)	(437,268)	(718,436)	(894,274)
Financing activities	(4,282)	99,737	473,857	667,931	964,288
Balance Sheet data:					
Cash and cash equivalents	\$17,224	\$201,229	\$184,405	\$67,517	\$109,509
Total property and equipment, net	1,114,372	947,500	993,968	1,722,827	1,018,084
Total assets	1,223,527	1,198,644	1,266,665	1,879,709	1,143,523

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Total debt	495,021	492,278	527,248	408,754	389,247
Total stockholders' equity	572,354	556,607	633,374	1,155,912	667,971
Other financial data:					
Adjusted EBITDAX	\$ 189,138	\$ 102,071	\$ 120,976	\$ 67,347	\$(11,018)

Non-GAAP Financial Measure

“Adjusted EBITDAX” is a non-GAAP financial measure that we define as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; DD&A; amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments, and premiums (paid) received on options that settled during the period; non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with U.S. GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with U.S. GAAP. Adjusted EBITDAX provides no information regarding a company’s capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company’s operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our revolving credit facility and the indenture governing our senior unsecured notes.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from operations to Adjusted EBITDAX for the periods presented:

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Net income (loss)	\$8,525	\$(206,735)	\$(961,791)	\$(179,975)	\$(43,541)
Depreciation, depletion and amortization	118,818	92,948	244,750	89,218	6,163
Exploration expense	50,208	52,775	116,211	21,186	3,022
Rig termination and standby	1	3,846	9,672	3,283	—
Stock-based compensation	9,301	6,216	4,635	256	43
Impairment of proved oil and gas properties	—	17,665	691,334	34,855	2,081
Accretion of asset retirement obligations	544	391	1,623	791	364
(Gain) loss on sale of assets	(179)	6,936	(4,737)	(960)	—
Gain on reduction of pension obligations	—	—	—	(2,208)	—
(Gain) loss on derivative instruments	(45,365)	52,338	(56,021)	(20,791)	—
Net cash receipts (payments) on settled	(2,224)	38,696	37,074	564	—

derivatives					
Net cash paid for option premium	—	—	—	(385)	—
Interest expense, net	49,490	50,789	53,400	48,347	20,850
(Gain) loss on early extinguishment of debt	—	(14,489)	59,392	—	—
Other (income) expense	19	149	(400)	(353)	—
Income tax (benefit) expense	—	546	(74,166)	73,519	—
Adjusted EBITDAX	\$189,138	\$102,071	\$120,976	\$67,347	\$(11,018)

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in natural gas, NGLs and oil prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." Also, see the risk factors and other cautionary statements described in "Item 1A. Risk Factors" of this Annual Report. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview of Our Business

We are an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin. As of December 31, 2017, we had assembled an acreage position approximating 203,000 net acres in Eastern Ohio. As of December 31, 2017 we had approximately 96,000 net acres in the Utica Shale in Eastern Ohio within the Utica Core Area, which we believe to be the most prolific part of the play and approximately 15,500 net acres are located in the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as our Marcellus Area. Additionally, we own approximately 107,000 net acres (which are approximately 71% held by production) outside of the Utica Core Area that may be prospective for the oil window of the Utica Shale.

We are the operator of approximately 93% of our proved reserves within the Utica Core Area and our Marcellus Area. We intend to focus on developing our substantial inventory of horizontal drilling locations during commodity price environments that will allow us to generate attractive returns and will continue to opportunistically add to this acreage position where we can acquire acreage at attractive prices.

As of December 31, 2017:

- we were operating 2 horizontal rigs in the Utica Core Area;
- we, or our operating partners, had commenced drilling 234 gross (124.4 net) wells within the Utica Core Area and our Marcellus Area, of which 5 gross (3.8 net) were top holed, 2 gross (0.9 net) were drilling, 14 gross (9.2 net) were awaiting completion, 2 gross (2.0 net) were awaiting midstream and 211 gross (108.5 net) had been turned to sales.
 - we had average daily production for the year ended December 31, 2017 of approximately 310.7 MMcf, which was comprised of approximately 77% natural gas, 14% NGLs and 9% oil; and
- our estimated proved reserves were 1,458.6 Bcfe, or 243.1 MMBoe, based on reserve reports prepared by Netherland, Sewell & Associates, Inc., or NSAI, our independent petroleum engineers, all of which were in Ohio and approximately 31% of which were proved developed reserves. Our estimated proved reserves were approximately 75% natural gas, 17% NGLs and 8% oil, as of December 31, 2017.

Factors That Significantly Affect Our Financial Condition and Results of Operations

We derive substantially all of our revenues from the production and sale of natural gas, NGLs and oil that are extracted from our natural gas during processing. During the year ended December 31, 2017, our revenues were

comprised of approximately 63%, 17% and 19% from the production and sale of natural gas, NGLs and oil, respectively (with the remaining 1% of revenues attributable to brokered natural gas and marketing revenue). Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as

economic, political and regulatory developments and competition from other sources of energy. Natural gas, NGLs and oil prices have historically been volatile and may fluctuate widely in the future due to a variety of factors, including, but not limited to, prevailing economic conditions, supply and demand of hydrocarbons in the marketplace and geopolitical events such as wars or natural disasters. Sustained periods of low prices for these commodities would materially and adversely affect our financial condition, our results of operations, the quantities of natural gas, NGLs and oil that we can economically produce and our ability to access capital.

We use commodity derivative instruments to manage and reduce price volatility and other market risks associated with our production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter commodity derivative contracts with large financial institutions. Please read “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for additional discussion of our commodity derivative contracts.

Like other businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an exploration and production company depletes part of its asset base with each unit of reserves it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production in a cost effective manner. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost effective manner and to timely obtain drilling permits and regulatory approvals.

Our financial condition and results of operations, including the growth of production, cash flows and reserves, are driven by several factors, including:

- success in drilling new wells;
- natural gas, NGLs and oil prices;
- the availability of attractive acquisition opportunities and our ability to execute them;
- the amount of capital we invest in the leasing and development of our properties;
- facility or equipment availability and unexpected downtime;
 - delays imposed by or resulting from compliance with regulatory requirements; and
- the rate at which production volumes on our wells naturally decline.

Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Financing Arrangements. On July 6, 2015, we issued \$550 million in aggregate principal amount of 8.875% senior unsecured notes due 2023 at an issue price of 97.903% of the principal amount of the notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the senior unsecured notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside the United States in compliance with Regulation S under the Securities Act. Upon closing, we received proceeds of approximately \$525.5 million, after deducting original issue discount, the initial purchasers’ discounts and estimated offering expenses, of which we used approximately \$510.7 million to finance the redemption of all of our outstanding 12.0% Senior PIK Notes due 2018. We used the remaining net proceeds to fund our capital expenditure plan and for general corporate purposes.

During 2016, the Company repurchased \$39.5 million of outstanding senior unsecured notes in open market purchases for \$23.4 million. The principal of the outstanding senior unsecured notes that were repurchased less cash

proceeds and unamortized debt discount and deferred financing costs were charged to gain on early extinguishment of debt, totaling \$14.5 million for the fiscal year. The Company repurchased all such senior unsecured notes with cash on hand.

Drilling Joint Venture. On December 22, 2017, we entered into definitive agreements with Sequel (an affiliate of GSO Capital Partners LP) to establish a drilling joint venture on our Utica Shale acreage in Guernsey and Monroe counties in southeast Ohio. We have committed funding from Sequel of up to \$285 million to fund its proportionate share of two drilling programs comprising of 33 gross wells in aggregate, with the mutual option for an additional third well program consisting of approximately 16 wells (which would increase the committed funding). We will retain 50% of our pre-carry working interest in the first program and 30% of our pre-carry working interest in the second program. We have the option to adjust our pre-carry working interest in the third program, if applicable, to between 30% to 70%, which must be exercised prior to the commencement of the third program. We will receive a 15% carried interest on drilling and completion capital expenditures incurred in each well program, which will be proportionately reduced based upon our retained pre-carry working interest in such well program, and a significant portion of Sequel's working interest in each well program will revert to Eclipse once a certain return is realized by Sequel in each program. We will be the operator of all wells drilled within each well program.

Please see "Items 1 and 2. Business and Properties—Recent Developments" for a description of other recent developments and transactions that may affect the comparability of our historical financial condition and results of operations for the periods presented to future periods.

Source of Our Revenues

Substantially all of our historical revenues are derived from the production and sale of natural gas, NGLs and oil, and do not include the effects of derivatives. Revenues from product sales are a function of the volumes produced, prevailing market prices, product quality, gas Btu content and transportation costs. We generally sell production at a specific delivery point, pay transportation costs to a third party and receive proceeds from the purchaser with no transportation deduction. We record transportation costs as transportation, gathering and compression expense. We also may derive revenue from brokered gas or revenue we receive as a result of selling natural gas that is not related to our production and from the release of firm transportation capacity, which we refer to as brokered natural gas and marketing revenue. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Principal Components of Our Cost Structure

- **Lease operating.** These are day-to-day costs incurred to bring hydrocarbons out of the ground along with the daily costs incurred to maintain our producing properties. Such costs include compensation of our field employees, maintenance, repairs and workovers expenses related to our natural gas and oil properties.
- **Transportation, gathering and compression.** These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low- and high-pressure gathering and compression systems as well as fees paid to third parties who operate gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced gas and to transport our NGLs and oil to market. We often enter into fixed price long -term contracts that secure transportation and processing capacity which may include minimum volume commitments, the cost for which is included in these expenses to the extent that they are not excess capacity.
- **Production and ad valorem taxes.** Production taxes are paid on produced natural gas and oil based on a percentage of market prices or at fixed rates established by the applicable federal, state or local taxing authorities. Ad valorem taxes are generally based on reserve values at the end of each year.

Brokered natural gas and marketing. These expenses are gas purchases for brokered natural gas that we buy and sell that is not related to our production and firm transportation capacity that is marketed to third parties.

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• **Depreciation, depletion and amortization.** This includes the expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense.

• **Exploration.** These are geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. This category also includes unproved property impairment and expenses associated with lease expirations.

• **General and administrative.** These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance. Included in this category are any overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life.

• **Impairment of oil and gas properties.** Properties are evaluated for impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. When the carrying value exceeds the sum of the future undiscounted cash flows, an impairment loss is recognized for the difference between the fair market value and carrying value of the asset.

• **Accretion expense.** This expense includes the monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines and other facilities.

• **Gain (loss) on derivative instruments.** We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of gas. None of our derivative contracts are designated as hedges for accounting purposes. Consequently, our derivative contracts are marked-to-market each quarter with changes in fair value recognized currently as a gain or loss in our results of operations. The amount of future gain or loss recognized on derivative instruments is dependent upon future gas prices, which will affect the value of the contracts. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. In addition to gains and losses recognized from changes in fair value of the derivative instruments, gain (loss) on derivative instruments includes actual amounts realized from settlement of derivative instruments upon expiration.

• **Interest expense.** We have historically financed a portion of our cash requirements with proceeds from fixed-rate senior unsecured notes and our revolving credit facility. As a result, we incur interest expense that is affected by our financing decisions. We capitalize interest on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use. Upon completion of construction of the asset, the associated capitalized interest costs are included within our asset base and depleted accordingly.

How We Evaluate Our Operations

In evaluating our current and future financial results, we focus on production and revenue growth, lease operating expense, general and administrative expense (both before and after non-cash stock compensation expense) and operating margin per unit of production. In addition to these metrics, we use Adjusted EBITDAX, a non-GAAP measure, to evaluate our financial results. We define Adjusted EBITDAX as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; depreciation, depletion and amortization ("DD&A"); amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments, and premiums (paid) received on options that settled during the period; non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX is not a measure of net income as determined by generally accepted accounting principles in United States, or "U.S. GAAP."

In addition to the operating metrics above, as we grow our reserve base, we will assess our capital spending by calculating our operated proved developed reserves and our operated proved developed finding costs and

development costs. We believe that operated proved developed finding and development costs are one of the key measurements of the performance of an oil and gas exploration and production company. We will focus on our operated properties as we control the location, spending and operations associated with drilling these properties. In determining our proved developed finding and development costs, only cash costs incurred in connection with exploration and development will be used in the calculation, while the costs of acquisitions will be excluded because our board approves each material acquisition. In evaluating our proved developed reserve additions, any reserve revisions for changes in commodity prices between years will be excluded from the assessment, but any performance related reserve revisions are included.

We also continually evaluate our rates of return on invested capital in our wells. These rates of return calculations may include corporate level items such as land costs, general and administrative expenses, midstream costs and cash settled derivatives. We believe the quality of our assets combined with our technical and managerial expertise can generate attractive rates of return as we develop our acreage in the Utica Core Area and our Marcellus Area. We review changes in drilling and completion costs; lease operating costs; natural gas, NGLs and oil prices; well productivity; and other factors in order to focus our drilling on the highest rate of return areas within our acreage on a per well basis.

Overview of the Year Ended December 31, 2017 Results

Operationally, our performance during the year ended December 31, 2017 reflects continued development of our acreage, while focusing on capital preservation in the current commodity price environment. During the year ended December 31, 2017, we achieved the following financial and operating results:

- increased our average daily net production for the year ended December 31, 2017 by 36% over the prior year, to 310.7 MMcf per day;
- commenced drilling 29 gross (21.6 net) operated Utica and Marcellus Shale wells, commenced completions of 24 gross (21.3 net) operated Utica and Marcellus Shale wells and turned-to-sales 24 gross (22.2 net) operated Utica Shale wells during the year;
- recognized net income of \$8.5 million for the year ended December 31, 2017 compared to a net loss of (\$206.7) million for the year ended December 31, 2016; and
- realized Adjusted EBITDAX of \$189.1 million for the year ended December 31, 2017 compared to \$102.1 million for the year ended December 31, 2016. Adjusted EBITDAX is a non-GAAP financial measure. See “Item 6. Selected Financial Data—Non-GAAP Financial Measure” for more information.

Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. The following table lists average daily, high, low and average monthly settled NYMEX Henry Hub prices for natural gas and average daily, high and low NYMEX WTI prices for oil for the years ended December 31, 2017, 2016, and 2015.

	Year Ended December 31,		
	2017	2016	2015
NYMEX Henry Hub High (\$/MMBtu)	\$3.71	\$3.80	\$3.32
NYMEX Henry Hub Low (\$/MMBtu)	2.44	1.49	1.63
Average Daily NYMEX Henry Hub (\$/MMBtu)	2.99	2.52	2.57
Average Monthly Settled NYMEX Henry Hub	3.11	2.46	2.66

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(\$/MMBtu)

NYMEX WTI High (\$/Bbl)	\$60.46	\$54.01	\$61.36
NYMEX WTI Low (\$/Bbl)	42.48	26.19	34.55
Average Daily NYMEX WTI (\$/Bbl)	50.80	43.29	49.33

Historically, commodity prices have been extremely volatile, and we expect this volatility to continue for the foreseeable future. A decline in commodity prices could materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. We make price assumptions that are used for planning purposes, and a significant portion of our cash outlays, including rent, salaries and noncancelable capital commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

The Company is committed to profitably developing its natural gas, NGLs and condensate reserves through an environmentally responsible and cost-effective operational plan. The Company's revenues, earnings, liquidity and ability to grow are substantially dependent on the prices it receives for, and the Company's ability to develop its reserves. Despite the continued low price commodity environment, the Company believes the long-term outlook for its business is favorable due to the Company's resource base, low cost structure, risk management strategies, and disciplined investment of capital.

It is difficult to quantify the impact of changes in future commodity prices on our reported estimated net proved reserves with any degree of certainty because of the various components and assumptions used in the process. However, the below sensitivity analysis demonstrates the potential impact of a 10% increase and decrease in commodity pricing to our reserves and Standardized Measure assuming all other inputs remain constant.

	Standardized Measure of Discounted Future			
	Oil	Natural Gas	Estimated Proved Reserves (Bcfe)	Net Cash Flows (PV-10)
Commodity Pricing - SEC	\$51.34	\$ 2.98	1,458.6	\$ 729.7
Reserves Sensitivity:				
10% Increase	\$56.47	\$ 3.27	1,665.1	\$ 1,029.2
10% Decrease	\$46.21	\$ 2.68	1,002.2	\$ 472.5

We consider future commodity prices when determining our development plan, but many other factors are also considered. To the extent there is a significant increase or decrease in commodity prices in the future, we will assess the impact on our development plan at that time, and we may respond to such changes by altering our capital budget or our development plan. We plan to fund our development budget with a portion of the cash on hand at December 31, 2017, cash flows from operations, borrowings under our revolving credit facility, proceeds from asset sales, proceeds from our drilling joint venture, and proceeds from additional debt and/or equity offerings.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

The following table illustrates the revenue attributable to our operations for the years ended December 31, 2017 and 2016:

	Year Ended		
	December 31,		
	2017	2016	Change
Revenues (in thousands)			
Natural gas sales	\$241,379	\$134,618	\$106,761
NGL sales	64,109	38,204	25,905
Oil sales	74,690	50,193	24,497
Brokered natural gas and marketing revenue	3,481	12,019	(8,538)
Total revenues	\$383,659	\$235,034	\$148,625

Our production grew by approximately 29.8 Bcfe for the year ended December 31, 2017 over the year ended December 31, 2016, as we placed new wells into production, partially offset by natural declines in well production. Our production for the years ended December 31, 2017 and 2016 is set forth in the following table:

	Year Ended		
	December 31, 2017	2016	Change
Production:			
Natural gas (MMcf)	87,404.2	60,921.9	26,482.3
NGLs (Mbbbls)	2,713.7	2,446.2	267.5
Oil (Mbbbls)	1,622.4	1,343.8	278.6
Total (MMcfe)	113,420.8	83,661.9	29,758.9
Average daily production volume:			
Natural gas (Mcf/d)	239,464	166,453	73,011
NGLs (Bbls/d)	7,435	6,684	751
Oil (Bbls/d)	4,445	3,672	773
Total (Mcfe/d)	310,744	228,589	82,155

Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the year ended December 31, 2017 was \$2.99 per Mcfe compared to \$2.76 per Mcfe during the year ended December 31, 2016. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales price (excluding cash settled derivatives) does not include derivative settlements or third party transportation costs, which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales price (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the years ended December 31, 2017 and 2016 are shown below:

	Year Ended		
	December 31, 2017	2016	Change
Average realized price (excluding cash settled derivatives and firm transportation)			
Natural gas (\$/Mcf)	\$2.76	\$2.21	\$ 0.55
NGLs (\$/Bbl)	23.62	15.62	8.00
Oil (\$/Bbl)	46.04	37.35	8.69
Total average prices (\$/Mcfe)	3.35	2.67	0.68
Average realized price (including cash settled derivatives, excluding firm transportation)			
Natural gas (\$/Mcf)	\$2.79	\$2.69	\$ 0.10
NGLs (\$/Bbl)	21.96	15.55	6.41
Oil (\$/Bbl)	46.14	44.66	1.48
Total average prices (\$/Mcfe)	3.33	3.13	0.20
Average realized price (including firm transportation, excluding cash settled derivatives)			
Natural gas (\$/Mcf)	\$2.31	\$1.71	\$ 0.60
NGLs (\$/Bbl)	23.62	15.62	8.00
Oil (\$/Bbl)	46.04	37.35	8.69
Total average prices (\$/Mcfe)	3.01	2.30	0.71
Average realized price (including cash settled derivatives and firm transportation)			
Natural gas (\$/Mcf)	\$2.34	\$2.19	\$ 0.15
NGLs (\$/Bbl)	21.96	15.55	6.41
Oil (\$/Bbl)	46.14	44.66	1.48

Total average prices (\$/Mcf)	2.99	2.76	0.23
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Brokered natural gas and marketing revenue was \$3.5 million for the year ended December 31, 2017 compared to \$12.0 million in the year ended December 31, 2016. Brokered natural gas and marketing revenue includes revenue we receive as a result of selling natural gas that is not related to our production and from the release of firm transportation capacity. The decrease from the year ended December 31, 2016 to the year ended December 31, 2017 is due to increased utilization of our firm transportation capacity for operated production during the year ended December 31, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Costs and Expenses

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per Mcfe, basis. The following table presents information about certain of our expenses for the years ended December 31, 2017 and 2016.

	Year Ended		
	December 31,		
	2017	2016	Change
Operating expenses (in thousands)			
Lease operating	\$20,525	\$9,023	\$11,502
Transportation, gathering and compression	124,839	109,226	15,613
Production and ad valorem taxes	8,490	7,927	563
Depreciation, depletion and amortization	118,818	92,948	25,870
General and administrative	44,553	39,431	5,122
Operating expenses per Mcfe:			
Lease operating	\$0.18	\$0.11	\$0.07
Transportation, gathering and compression	1.10	1.30	(0.20)
Production and ad valorem taxes	0.07	0.09	(0.02)
Depreciation, depletion and amortization	1.05	1.11	(0.06)
General and administrative	0.39	0.47	(0.08)

Lease operating expense was \$20.5 million in the year ended December 31, 2017 compared to \$9.0 million in the year ended December 31, 2016. Lease operating expense per Mcfe was \$0.18 in the year ended December 31, 2017 compared to \$0.11 in the year ended December 31, 2016. The increase of \$11.5 million and \$0.07 per Mcfe is attributable to increases in producing wells, salt water disposal expenses and workover expenses during the year ended December 31, 2017. Lease operating expenses include normally recurring expenses to operate our wells and non-recurring workovers and repairs.

Transportation, gathering and compression expense was \$124.8 million in the year ended December 31, 2017 compared to \$109.2 million in the year ended December 31, 2016. Transportation, gathering and compression expense per Mcfe was \$1.10 in the year ended December 31, 2017 compared to \$1.30 in the year ended December 31, 2016. The following table details our transportation, gathering and compression expenses for the years ended December 31, 2017 and 2016:

	Year Ended		
	December 31,		
	2017	2016	Change
Transportation, gathering and compression (in thousands):			
Gathering, compression and fuel	\$46,466	\$38,474	\$7,992
Processing and fractionation	32,468	32,067	401
Liquids transportation and stabilization	6,746	8,225	(1,479)
Marketing	27	54	(27)

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Firm transportation	39,132	30,406	8,726
	\$124,839	\$109,226	\$15,613
Transportation, gathering and compression per Mcfe:			
Gathering, compression and fuel	\$0.41	\$0.46	\$(0.05)
Processing and fractionation	0.29	0.38	(0.09)
Liquids transportation and stabilization	0.06	0.10	(0.04)
Marketing	—	—	—
Firm transportation	0.34	0.36	(0.02)
	\$1.10	\$1.30	\$(0.20)

The increase of \$15.6 million in the year ended December 31, 2017 was due to our production growth and increased firm transportation expenses, which increased primarily due to additional capacity that came online during the fourth quarter of 2016. The decrease of \$0.20 on a per unit basis was primarily due to increased production associated with natural gas and lower contractual rates.

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were \$8.5 million in the year ended December 31, 2017 compared to \$7.9 million in the year ended December 31, 2016. Production and ad valorem taxes per Mcfe was \$0.07 in the year ended December 31, 2017 compared to \$0.09 in the year ended December 31, 2016. The increase in aggregate production and ad valorem taxes is primarily due to increased well count. The decrease in production and ad valorem taxes on a per unit basis is due to the lower taxable value rate for the year ended December 31, 2017.

Depletion, depreciation and amortization was approximately \$118.8 million for the year ended December 31, 2017 compared to \$92.9 million in the year ended December 31, 2016. This increase is primarily due to an increase in production and proved property costs. On a per Mcfe basis, DD&A decreased to \$1.05 in the year ended December 31, 2017 from \$1.11 in the year ended December 31, 2016, which was primarily due to a lower depletion rate resulting from increased reserves.

General and administrative expense was \$44.6 million for the year ended December 31, 2017 compared to \$39.4 million for the year ended December 31, 2016. General and administrative expense per Mcfe was \$0.39 in the year ended December 31, 2017 compared to \$0.47 in the year ended December 31, 2016. The aggregate increase of \$5.1 million was primarily due to higher salaries and benefits associated with increased head count and the decrease of \$0.08 per Mcfe was primarily due to fixed costs spread across increased levels of production, in each case, as of December 31, 2017 compared to December 31, 2016. General and administrative expense includes \$9.3 million and \$6.2 million of stock-based compensation expense for the years ended December 31, 2017 and December 31, 2016, respectively.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include brokered natural gas and marketing expense, exploration, rig termination and standby, accretion of asset retirement obligations, impairment of proved oil and natural gas properties and (gain) loss on sale of assets. The following table details our other operating expenses for the years ended December 31, 2017 and 2016.

	Year Ended		
	December 31, 2017	2016	Change
Other operating expenses (in thousands):			
Brokered natural gas and marketing expense	\$3,191	\$12,268	\$(9,077)
Exploration	50,208	52,775	(2,567)
Rig termination and standby	1	3,846	(3,845)
Impairment of proved oil and natural gas properties	—	17,665	(17,665)
Accretion of asset retirement obligations	544	391	153
(Gain) loss on sale of assets	(179)	6,936	(7,115)

Brokered natural gas and marketing expense was \$3.2 million for the year ended December 31, 2017 compared to \$12.3 million in the year ended December 31, 2016. Brokered natural gas and marketing expenses relate to gas purchases for brokered natural gas that we buy and sell that is not related to our production and firm transportation capacity that is marketed to third parties. The decrease is primarily due to increased utilization of our firm transportation capacity for operated production during the year ended December 31, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Exploration expense decreased to \$50.2 million in the year ended December 31, 2017 compared to \$52.8 million in the year ended December 31, 2016. The following table details our exploration-related expenses for the years ended December 31, 2017 and 2016.

	Year Ended		
	December 31, 2017	2016	Change
Exploration expenses (in thousands):			
Geological and geophysical	\$1,098	\$935	\$163
Delay rentals	17,693	20,987	(3,294)
Impairment of unproved properties	28,291	29,824	(1,533)
Dry hole and other	3,126	1,029	2,097
	\$50,208	\$52,775	\$(2,567)

Delay rentals were \$17.7 million for the year ended December 31, 2017 compared to \$21.0 million for the year ended December 31, 2016. The decrease in delay rentals relates to the reduction of converting future lump-sum extension payments into annual delay rentals and increased drilling activity during 2017.

Impairment of unproved properties was \$28.3 million for the year ended December 31, 2017 compared to \$29.8 million for the year ended December 31, 2016. The decrease in impairment charges during the year ended December 31, 2017 was the result of a decrease in expected lease expirations due to the increase in our planned future drilling activity. As we continue to review our acreage positions and high grade our drilling inventory based on the current commodity price environment, additional leasehold impairments and abandonments may be recorded.

Rig termination and standby expense was less than \$0.1 million for the year ended December 31, 2017. For the year ended December 31, 2016, rig termination and standby expenses were \$3.8 million related primarily to standby costs incurred from temporarily suspending our drilling operations for a portion of 2016.

Impairment of proved oil and natural gas properties was \$17.7 million for the year ended December 31, 2016 related to certain of our Marcellus Shale properties. There was no impairment of proved oil and gas properties recognized for the year ended December 31, 2017.

Accretion of asset retirement obligations was \$0.5 million in the year ended December 31, 2017, compared to \$0.4 million in the year ended December 31, 2016. The increase in accretion expense primarily relates to the increase in our number of producing wells.

(Gain) loss on sale of assets was (\$0.2) million for the year ended December 31, 2017 due primarily to the sale of certain non-core assets. The loss of \$6.9 million for the year ended December 31, 2016 was due primarily to realizing a loss on the sale of approximately 9,900 net acres to a third party.

Other Income (Expense)

Gain (loss) on derivative instruments was \$45.4 million for the year ended December 31, 2017 compared to (\$52.3) million for the year ended December 31, 2016, primarily due to changes in commodity prices during each year. Cash receipts (payments) were approximately (\$2.2) million and \$38.7 million for the derivative instruments that settled during the years ended December 31, 2017 and December 31, 2016, respectively.

Interest expense, net was \$49.5 million for the year ended December 31, 2017 compared to \$50.8 million for year ended December 31, 2016. The decrease in interest expense was primarily due to the early extinguishment of debt during the year ended December 31, 2016, as described in the following paragraph.

Gain on early extinguishment of debt was \$14.5 million for the year ended December 31, 2016 resulting from the repurchase of \$39.5 million in aggregate principal amount of our outstanding senior unsecured notes in the

open market for \$23.4 million during such year. The outstanding principal amount of senior unsecured notes that we repurchased less cash proceeds and unamortized debt discount and deferred financing costs of \$1.6 million were charged to gain on early extinguishment of debt. No gain or loss on early extinguishment of debt was recognized for the year ended December 31, 2017.

Income tax benefit (expense) was (\$0.5) million for the year ended December 31, 2016 related to the write-off of certain state deferred tax assets. No income tax benefit or expense was recorded for the year ended December 31, 2017 due to reducing the valuation allowance to the extent of the tax effect of recorded pre-tax income. Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act, resulted in the Company generating a deferred tax expense of \$142 million primarily due to remeasurement of our net deferred tax asset for the reduction in the U.S. statutory rate from 35% to 21%. Based on our current interpretation and subject to release of the related regulations and any future interpretative guidance, we believe the effects of the change in tax law incorporated herein are substantially complete. See Note 14— Income Tax to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for information regarding the impact of the Tax Cuts and Jobs Act on our income tax provisions for the year ended December 31, 2017. At December 31, 2017, we had approximately \$546 million of NOLs for U.S. federal income tax purposes that expire at various dates from 2034 through 2037. The increase in NOLs from approximately \$426 million at December 31, 2016 to \$546 million at December 31, 2017 results primarily from the deduction of intangible drilling costs for U.S. federal income tax purposes. Future interpretations relating to the recently enacted U.S. federal income tax legislations, which vary from our current interpretation, may have a significant effect on our future taxable position. The impact of any such change would be recorded in the period in which such interpretations is received or legislation is enacted.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

The following table illustrates the revenue attributable to our operations for the years ended December 31, 2016 and 2015.

	Year Ended December 31,		
	2016	2015	Change
Revenues (in thousands):			
Natural gas sales	\$ 134,618	\$ 129,561	\$ 5,057
NGLs sales	38,204	30,177	8,027
Oil sales	50,193	74,863	(24,670)
Brokered natural gas and marketing revenue	12,019	20,720	(8,701)
Total revenues	\$ 235,034	\$ 255,321	\$ (20,287)

Our production grew by approximately 7.8 Bcfe for the year ended December 31, 2016 over the year ended December 31, 2015, as we placed new wells into production, partially offset by natural declines in well production. Our production for the years ended December 31, 2016 and 2015 is set forth in the following table:

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	Year Ended December 31,		
	2016	2015	Change
Production:			
Natural gas (MMcf)	60,921.9	49,477.6	11,444.3
NGLs (Mbbbls)	2,446.2	2,450.3	(4.1)
Oil (Mbbbls)	1,343.8	1,950.5	(606.7)
Total (MMcfe)	83,661.9	75,882.4	7,779.5
Average daily production volume:			
Natural gas (Mcf/d)	166,453	135,555	30,898
NGLs (Bbbls/d)	6,684	6,713	(29)
Oil (Bbbls/d)	3,672	5,344	(1,672)
Total (Mcfe/d)	228,589	207,897	20,692

Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the year ended December 31, 2016 was \$2.76 per Mcfe compared to \$3.38 per Mcfe during the year ended December 31, 2015. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales price (excluding cash settled derivatives) does not include derivative settlements or third party transportation costs, which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales price (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the years ended December 31, 2016 and 2015 are shown below:

	Year Ended December 31,		
	2016	2015	Change
Average realized price (excluding cash settled derivatives)			
Natural gas (\$/Mcf)	\$2.21	\$2.62	\$ (0.41)
NGLs (\$/Bbl)	15.62	12.32	3.30
Oil (\$/Bbl)	37.35	38.38	(1.03)
Total average prices (\$/Mcfe)	2.67	3.09	(0.42)
Average realized price (including cash settled derivatives)			
Natural gas (\$/Mcf)	\$2.69	\$3.27	\$ (0.58)
NGLs (\$/Bbl)	15.55	12.32	3.23
Oil (\$/Bbl)	44.66	40.92	3.74
Total average prices (\$/Mcfe)	3.13	3.58	(0.45)
Average realized price (including firm transportation)			
Natural gas (\$/Mcf)	\$1.71	\$2.31	\$ (0.60)
NGLs (\$/Bbl)	15.62	12.32	3.30
Oil (\$/Bbl)	37.35	38.38	(1.03)
Total average prices (\$/Mcfe)	2.30	2.89	(0.59)
Average realized price (including cash settled derivatives and firm transportation)			
Natural gas (\$/Mcf)	\$2.19	\$2.95	\$ (0.76)
NGLs (\$/Bbl)	15.55	12.32	3.23
Oil (\$/Bbl)	44.66	38.38	6.28
Total average prices (\$/Mcfe)	2.76	3.38	(0.62)

Brokered natural gas and marketing revenue was \$12.0 million for the year ended December 31, 2016 compared to \$20.7 million in the year ended December 31, 2015. Brokered natural gas and marketing revenue includes revenue we receive as a result of selling natural gas that is not related to our production and from the release of firm transportation

capacity. The decrease from the year ended December 31, 2015 to the year ended December 31, 2016 is due to increased utilization of our firm transportation capacity for operated production during the year ended December 31, 2016, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Costs and Expenses

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per Mcfe, basis. The following table presents information about certain of our expenses for the years ended December 31, 2016 and 2015.

	Year Ended December 31,		
	2016	2015	Change
Operating expenses (in thousands):			
Lease operating	\$9,023	\$13,904	\$(4,881)
Transportation, gathering and compression	109,226	85,846	23,380
Production and ad valorem taxes	7,927	3,722	4,205
Depreciation, depletion and amortization	92,948	244,750	(151,802)
General and administrative	39,431	46,409	(6,978)
Operating expenses per Mcfe:			
Lease operating	\$0.11	\$0.18	\$(0.07)
Transportation, gathering and compression	1.30	1.13	0.17
Production and ad valorem taxes	0.09	0.05	0.04
Depletion, depreciation and amortization	1.11	3.23	(2.12)
General and administrative	0.47	0.61	(0.14)

Lease operating expense was \$9.0 million in the year ended December 31, 2016 compared to \$13.9 million in the year ended December 31, 2015. Lease operating expense per Mcfe was \$0.11 in the year ended December 31, 2016 compared to \$0.18 in the year ended December 31, 2015. The decrease of \$4.9 million and \$0.07 per Mcfe is attributable to reduced personnel costs, in part due to the sale of our conventional oil and gas properties, and additional cost-cutting measures during the year ended December 31, 2016. Lease operating expenses include normally recurring expenses to operate our wells and non-recurring workovers and repairs.

Transportation, gathering and compression expense was \$109.2 million in the year ended December 31, 2016 compared to \$85.8 million in the year ended December 31, 2015. Transportation, gathering and compression expense per Mcfe was \$1.30 in the year ended December 31, 2016 compared to \$1.13 in the year ended December 31, 2015. The following table details our transportation, gathering and compression expenses for the years ended December 31, 2016 and 2015:

	Year Ended December 31,		
	2016	2015	Change
Transportation, gathering and compression			
(in thousands):			
Gathering, compression and fuel	\$38,474	\$30,079	\$8,395
Processing and fractionation	32,067	30,899	1,168
Liquids transportation and stabilization	8,225	9,342	(1,117)
Marketing	54	48	6

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Firm transportation	30,406	15,478	14,928
	\$109,226	\$85,846	\$23,380

Transportation, gathering and compression per

Mcf:

Gathering, compression and fuel	\$0.46	\$0.40	\$0.06
Processing and fractionation	0.38	0.41	(0.03)
Liquids transportation and stabilization	0.10	0.12	(0.02)
Marketing	—	—	—
Firm transportation	0.36	0.20	0.16
	\$1.30	\$1.13	\$0.17

The increase to expenses were attributable to higher costs in the year ended December 31, 2016 due to our production growth where we have third party gathering and compression agreements and increased firm transportation expenses, which increased primarily due to additional capacity that came online during the year ended December 31, 2016. The increase on a per unit basis was primarily due to firm transportation expenses related to the new capacity.

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were \$7.9 million in the year ended December 31, 2016 compared to \$3.7 million in the year ended December 31, 2015. Production and ad valorem taxes per Mcfe was \$0.09 in the year ended December 31, 2016 compared to \$0.05 in the year ended December 31, 2015. Production and ad valorem taxes increased from the year ended December 31, 2015 to the year ended December 31, 2016 primarily due to more wells calculated at the higher percentage.

Depletion, depreciation and amortization was approximately \$92.9 million for the year ended December 31, 2016 compared to \$244.8 million in the year ended December 31, 2015. The decrease in the year ended December 31, 2016 when compared to the year ended December 31, 2015 is primarily due to a reduction in proved property costs from impairment charges taken during 2015. On a per Mcfe basis, DD&A decreased to \$1.11 in the year ended December 31, 2016 from \$3.23 in the year ended December 31, 2015, which was primarily due to a lower depletion rate resulting from our reduced proved property costs.

General and administrative expense was \$39.4 million for the year ended December 31, 2016 compared to \$46.4 million for the year ended December 31, 2015. General and administrative expense per Mcfe was \$0.47 in the year ended December 31, 2016 compared to \$0.61 in the year ended December 31, 2015. The decrease of \$7.0 million and \$0.14 per Mcfe during the year ended December 31, 2016 when compared to year ended December 31, 2015 was primarily due to lower salaries and benefits associated with reduced head count from the sale of our conventional oil and gas properties during 2016. General and administrative expense includes \$6.2 million and \$4.6 million of stock-based compensation expense for the year ended December 31, 2016 and 2015, respectively.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include brokered natural gas and marketing expense, exploration, rig termination and standby, accretion of asset retirement obligations, impairment of proved oil and natural gas properties and (gain) loss on sale of assets. The following table details our other operating expenses for the years ended December 31, 2016 and 2015.

	Year Ended December 31,		
	2016	2015	Change
Other operating expenses (in thousands):			
Brokered natural gas and marketing expense	\$12,268	\$26,173	\$(13,905)
Exploration	52,775	116,211	(63,436)
Rig termination and standby	3,846	9,672	(5,826)
Accretion of asset retirement obligations	391	1,623	(1,232)
Impairment of proved oil and natural gas properties	17,665	691,334	(673,669)
(Gain) loss on sale of assets	6,936	(4,737)	11,673

Brokered natural gas and marketing expense was \$12.3 million for the year ended December 31, 2016 compared to \$26.2 million in the year ended December 31, 2015. Brokered natural gas and marketing expenses relate to gas purchases for brokered natural gas that we buy and sell that is not related to our production and firm transportation capacity that is marketed to third parties. The decrease is primarily due to increased utilization of our firm transportation capacity for operated production during the year ended December 31, 2016, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Exploration expense decreased to \$52.8 million in the year ended December 31, 2016 compared to \$116.2 million in the year ended December 31, 2015. The decrease is primarily due to a decrease in impairment charges taken in 2016. The following table details our exploration-related expenses for the years ended December 31, 2016 and 2015.

	Year Ended December 31,		
	2016	2015	Change
Exploration expenses (in thousands):			
Geological and geophysical	\$935	\$435	\$500
Delay rentals	20,987	19,692	1,295
Impairment of unproved properties	29,824	95,573	(65,749)
Dry hole and other	1,029	511	518
	\$52,775	\$116,211	\$(63,436)

Impairment of unproved properties was \$29.8 million for the year ended December 31, 2016 compared to \$95.6 million for the year ended December 31, 2015. The increase in impairment charges related to unproved properties during the year ended December 31, 2015 was the result of an increase in expected lease expirations due to the reduction in our planned future drilling activity due to the then-current commodity pricing environment. As we continue to review our acreage positions and high grade our drilling inventory based on the current commodity price environment, additional leasehold impairments and abandonments may be recorded.

Rig termination and standby expense was \$3.8 million for the year ended December 31, 2016, which is related primarily to standby costs that we incurred from temporarily suspending our drilling operations for a portion of 2016. For the year ended December 31, 2015, rig termination and standby expenses were \$9.7 million related primarily to rig termination expenses.

Accretion of asset retirement obligations was \$0.4 million in the year ended December 31, 2016, compared to \$1.6 million in the year ended December 31, 2015. The decrease in accretion expense primarily relates to the sale of our conventional assets and liabilities during the year ended December 31, 2016.

Impairment of proved oil and natural gas properties was \$17.7 million for the year ended December 31, 2016 compared to \$691.3 million for the year ended December 31, 2015. An analysis of proved properties determined the future undiscounted cash flows were less than the carrying value for certain asset groupings. An impairment expense was recognized for these asset groupings based on the difference between the fair market value and carrying value of the asset groupings. The impairment recorded for the year ended December 31, 2016 related to certain of our Marcellus Shale properties and the impairment recorded for the year ended December 31, 2015 related to certain of our Utica Shale properties.

(Gain) loss on sale of assets was \$6.9 million for the year ended December 31, 2016 due primarily to realizing a loss on the sale of approximately 9,900 net acres to a third party. The gain of (\$4.7) million for the year ended December 31, 2015 was due to the sale of a central processing facility and certain pipelines.

Other Income (Expense)

Gain (loss) on derivative instruments was (\$52.3) million for the year ended December 31, 2016 compared to \$56.0 million for the year ended December 31, 2015, primarily due to changes in commodity prices during each year. Cash

receipts were approximately \$38.7 million and \$37.1 million for the derivative instruments that settled during the years ended December 31, 2016 and December 31, 2015, respectively.

Interest expense, net was \$50.8 million for the year ended December 31, 2016 compared to \$53.4 million for year ended December 31, 2015. The decrease in interest expense was due to a lower interest rate on our senior unsecured notes and reduced interest from the repurchase of long-term debt during the year ended December 31, 2016 compared to the year ended December 31, 2015, as described in the following paragraph.

Gain (loss) on early extinguishment of debt was \$14.5 million for the year ended December 31, 2016 compared to (\$59.4) million for the year ended December 31, 2015. The gain during the year ended December 31, 2016 resulted from the repurchase of \$39.5 million of our outstanding senior unsecured notes in the open market for \$23.4 million during such year. The principal amount of outstanding senior unsecured notes that we repurchased less cash proceeds and unamortized debt discount and deferred financing costs of \$1.6 million were charged to gain on early extinguishment of debt. The loss during the year ended December 31, 2015 resulted from the redemption of our outstanding 12.0% Senior PIK notes during such year, which was comprised of the make-whole premium of \$47.6 million and unamortized discount and deferred financing costs of \$11.8 million.

Income tax benefit (expense) was (\$0.5) million for the year ended December 31, 2016 compared to \$74.2 million for the year ended December 31, 2015. The income tax expense for the year ended December 31, 2016 was due to a write-off of state deferred tax assets recorded for the year ended December 31, 2015 while the income tax benefit for the year ended December 31, 2015 was primarily due to pre-tax loss incurred in 2015.

Cash Flows, Capital Resources and Liquidity

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices. Our cash flows from operations also are impacted by changes in working capital. Short-term liquidity needs are satisfied by our operating cash flow, proceeds from asset sales, borrowings under our revolving credit facility, proceeds from the drilling joint venture, and proceeds from issuances of debt and equity securities. We sell a large portion of our production at the wellhead under floating market contracts.

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Net cash provided by operations in the year ended December 31, 2017 was \$112.7 million compared to \$6.4 million in the year ended December 31, 2016. The increase in cash provided from operating activities reflects the increase in our production and commodity prices during the year-over-year comparative periods, working capital changes and the timing of cash receipts and disbursements.

Net cash used in investing activities in the year ended December 31, 2017 was \$292.5 million compared to \$89.3 million in the year ended December 31, 2016.

During the year ended December 31, 2017, we:

- spent \$291.8 million on capital expenditures for oil and natural gas properties;
- spent \$2.0 million on property and equipment; and
- received \$1.3 million of proceeds relating to the sale of assets.

During the year ended December 31, 2016, we:

- spent \$167.4 million on capital expenditures for oil and natural gas properties;
- spent \$1.2 million on property and equipment; and
- received \$79.2 million of proceeds relating to the sale of assets.

Net cash provided by (used in) financing activities in the year ended December 31, 2017 was (\$4.3) million compared to \$99.7 million in the year ended December 31, 2016.

During the year ended December 31, 2017, we:

paid \$1.8 million in financing costs associated with an amendment to the credit agreement governing our revolving credit facility that, among other things, increased the borrowing base under such revolving credit facility; and

paid \$2.0 million to repurchase stock in relation to tax withholding for settlement of equity compensation awards. During the year ended December 31, 2016, we:

- purchased outstanding senior unsecured notes with aggregate principal amount of \$39.5 million for \$23.4 million; and
- completed a public offering of 37,500,000 shares of common stock for approximately \$123.8 million of net proceeds.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Net cash provided by operations in the year ended December 31, 2016 was \$6.4 million compared to \$80.3 million in the year ended December 31, 2015. The decrease in cash provided from operating activities reflects the decreased commodity prices during the year ended December 31, 2016, partially offset by higher production. Net cash provided from operations is also affected by working capital changes and the timing of cash receipts and disbursements.

Net cash used in investing activities in the year ended December 31, 2016 was \$89.3 million compared to \$437.3 million in the year ended December 31, 2015.

During the year ended December 31, 2016, we:

- spent \$167.4 million on capital expenditures for oil and natural gas properties;
- spent \$1.2 million on property and equipment; and
- received \$79.2 million of proceeds relating to the sale of assets.

During the year ended December 31, 2015, we:

- spent \$475.7 million on capital expenditures for oil and natural gas properties;
- spent \$1.7 million on property and equipment; and
- received \$40.1 million of proceeds from the sale of gathering facilities and equipment.

Net cash provided by financing activities in the year ended December 31, 2016 was \$99.7 million compared to \$473.9 million in the year ended December 31, 2015.

During the year ended December 31, 2016, we:

- purchased outstanding senior unsecured notes with aggregate principal amount of \$39.5 million for \$23.4 million; and
- completed a public offering of 37,500,000 shares of common stock for approximately \$123.8 million of net proceeds.

During the year ended December 31, 2015, we:

- issued shares of common stock in a private placement transaction for proceeds to us totaling approximately \$434.1 million, net of \$5.9 million of issuance costs;
- received net proceeds of \$525.2 million from the issuance of senior unsecured notes, net of debt issuance costs; and
- paid \$485.3 million for the redemption of our 12.0% Senior PIK notes due 2018, comprised of outstanding principal balance of \$437.3 million, a make-whole premium of \$47.6 million and accrued interest.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, asset sales, borrowings under our revolving credit facility, proceeds from our drilling joint venture and access to the debt and equity capital markets. We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs, which requires substantial capital expenditures. We periodically review capital expenditures and adjust our budget based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices. We believe that our existing cash on hand, operating cash flow, proceeds from our drilling joint venture and available proceeds under our revolving credit facility will be adequate to meet our capital and operating requirements for 2018.

Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We will continue using net cash on hand, cash flows from operations, proceeds from our drilling joint venture and proceeds available under our revolving credit facility to satisfy near-term financial obligations and liquidity needs, and as necessary, we will seek additional sources of debt or equity to fund these requirements. Longer-term cash flows are subject to a number of variables including the level of production and prices we receive for our production as well as various economic conditions that have historically affected the natural gas and oil business. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales, joint venture transactions or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves

As of December 31, 2017, we were in compliance with all of our debt covenants under the credit agreement governing our revolving credit facility and the indenture governing our 8.875% senior unsecured notes due 2023. Further, based on our current forecast and activity levels, we expect to remain in compliance with all such debt covenants for the next twelve months. However, if oil and natural gas prices decrease to lower levels, we are likely to generate lower operating cash flows, which would make it more difficult for us to remain in compliance with all of our debt covenants, including requirements with respect to working capital and interest coverage ratios. This could negatively impact our ability to maintain sufficient liquidity and access to capital resources.

Credit Arrangements

Long-term debt at December 31, 2017 and December 31, 2016, excluding discount, totaled \$510.5 million.

Information related to our credit arrangements is described in Note 7— Debt to our consolidated financial statements and is incorporated herein by reference.

Commodity Hedging Activities

Our primary market risk exposure is in the prices we receive for our natural gas, NGLs and oil production. Realized pricing is primarily driven by the spot regional market prices applicable to our U.S. natural gas, NGLs and oil production. Pricing for natural gas, NGLs and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate the potential negative impact on our cash flow caused by changes in natural gas, NGLs and oil prices, we may enter into financial commodity derivative contracts to ensure that we receive minimum prices for a portion of our

future natural gas production when management believes that favorable future prices can be secured. We typically hedge the NYMEX Henry Hub price for natural gas, the WTI price for oil and a NGLs basket based on prices at Mont Belvieu, Texas.

Our hedging activities are intended to support natural gas, NGLs and oil prices at targeted levels and to manage our exposure to price fluctuations. The counterparty is required to make a payment to us for the difference between the floor price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the floor price. We are required to make a payment to the

counterparty for the difference between the ceiling price and the settlement price if the ceiling price is below the settlement price. These contracts may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, zero cost collars that set a floor and ceiling price for the hedged production, and puts which require us to pay a premium either up front or at settlement and allow us to receive a fixed price at our option if the put price is above the market price. As of December 31, 2017, we had entered into the following derivative contracts:

Natural Gas Derivatives

			Weighted Average
	Volume		
Description	(MMBtu/d)	Production Period	Price (\$/MMBtu)
Natural Gas Swaps:			
	30,000	January 2018 – March 2018	\$ 3.46
Natural Gas Three-way Collars:			
Floor purchase price (put)	30,000	January 2018 – March 2019	\$ 3.00
Ceiling sold price (call)	30,000	January 2018 – March 2019	\$ 3.40
Floor sold price (put)	30,000	January 2018 – March 2019	\$ 2.50
Floor purchase price (put)	40,000	January 2018 – March 2018	\$ 2.90
Floor purchase price (put)	40,000	April 2018 – December 2018	\$ 3.11
Ceiling sold price (call)	40,000	January 2018 – December 2018	\$ 3.38
Floor sold price (put)	40,000	January 2018 – December 2018	\$ 2.50
Floor purchase price (put)	60,000	January 2018 – March 2018	\$ 2.90
Ceiling sold price (call)	60,000	January 2018 – March 2018	\$ 3.75
Floor sold price (put)	60,000	January 2018 – March 2018	\$ 2.50
Floor purchase price (put)	60,000	January 2018 – December 2018	\$ 2.80
Ceiling sold price (call)	60,000	January 2018 – December 2018	\$ 3.35
Floor sold price (put)	60,000	January 2018 – December 2018	\$ 2.50
Natural Gas Call/Put Options:			
Call sold	40,000	January 2018 – December 2018	\$ 3.75
Call sold	10,000	January 2019 – December 2019	\$ 4.75
Basis Swaps:			
Appalachia - Dominion	60,000	January 2018 – March 2018	\$ (0.44)
Appalachia - Dominion	12,500	April 2019 – October 2019	\$ (0.52)
Appalachia - Dominion	12,500	April 2020 – October 2020	\$ (0.52)

Oil Derivatives

	Volume		Weighted Average
Description	(Bbbls/d)	Production Period	Price (\$/Bbl)
Oil Three-way Collars:			

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Floor purchase price (put)	4,000	January 2018 – December 2018	\$ 45.00
Ceiling sold price (call)	4,000	January 2018 – December 2018	\$ 52.25
Floor sold price (put)	4,000	January 2018 – December 2018	\$ 35.00

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have derivative instruments in place with Bank of Montreal, Citibank, N.A., KeyBank N.A., Morgan Stanley,

Capital One N.A., BP Energy Company and Goldman Sachs. We believe all of such institutions currently are an acceptable credit risk. As of December 31, 2017, we did not have any past due receivables from counterparties.

Subsequent to December 31, 2017, we entered into the following derivative instruments to mitigate our exposure to commodity prices:

Natural Gas:

Description	Volume		Weighted Average
	(MMbtu/d)	Production Period	Price (\$/MMbtu)
Natural Gas Swaps:			
	30,000	April 2018 – March 2019	\$ 2.90

Oil:

Description	Volume		Weighted Average
	(Bbls/d)	Production Period	Price (\$/Bbl)
Oil Swaps:			
	1,000	July 2018 – March 2019	\$ 61.00
Oil Three-way Collars:			
Floor purchase price (put)	2,000	January 2019 – December 2019	\$ 50.00
Ceiling sold price (call)	2,000	January 2019 – December 2019	\$ 60.56
Floor sold price (put)	2,000	January 2019 – December 2019	\$ 40.00
Oil Call/Put Options:			
Ceiling sold price (call)	1,000	February 2018 – December 2018	\$ 57.12
Ceiling purchased price (call)	1,000	February 2018 – December 2018	\$ 52.25

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of natural gas and oil properties and repayment of principal and interest on outstanding debt. The Board of Directors recently approved an initial capital budget for 2018 of between approximately \$300 - \$320 million, allocated approximately 84% for drilling and completions activities, 8% for midstream activities, 6% for land activities and 2% for other capital requirements. The 2018 capital budget is expected to be substantially funded through internally generated cash flows and the Company's current cash balance, proceeds from our drilling joint venture, borrowings under the revolving credit facility and/or other debt and equity offerings. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas, NGLs and oil prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive

developments. A reduction in natural gas, NGLs or oil prices from current levels may result in a further decrease in our actual capital expenditures, which would negatively impact our ability to grow production and our proved reserves as well as our ability to maintain compliance with our debt covenants. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities, additional borrowings under our revolving credit facility or the sale of assets.

In addition, we may from time to time seek to pay down, retire or repurchase our outstanding debt using cash or through exchanges of other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on available funds, prevailing market conditions, our liquidity requirements, contractual restrictions in our revolving credit agreement and other factors.

Capitalization

As of December 31, 2017 and December 31, 2016, our total debt, excluding debt discount and issuance costs, and capitalization were as follows (in millions):

	December 31, 2017	December 31, 2016
Senior unsecured notes	\$ 510.5	\$ 510.5
Stockholders' equity	572.4	556.6
Total capitalization	\$ 1,082.9	\$ 1,067.1

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, firm transportation, gas processing, gathering and compressions services, and asset retirement obligations. As of December 31, 2017 and December 31, 2016, we did not have any capital leases, any significant off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed any debt of any unrelated party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2017. In addition to the contractual obligations listed in the table below, our balance sheet at December 31, 2017 reflects accrued interest payable of \$21.1 million, compared to \$21.1 million as of December 31, 2016. We paid the accrued interest balance in January 2018.

The following summarizes our contractual financial obligations at December 31, 2017 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our revolving credit facility, additional debt and equity issuances, proceeds from our drilling joint venture and proceeds from asset sales (in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Senior unsecured notes ⁽¹⁾	\$—	\$—	\$—	\$—	\$—	\$510,465	\$510,465
Drilling rig commitments ⁽²⁾	11,678	—	—	—	—	—	11,678
Firm transportation ⁽³⁾	84,167	109,716	109,976	105,773	102,476	885,139	1,397,247
Gas processing, gathering, and compression services ⁽⁴⁾	14,186	15,407	6,999	—	—	—	36,592
Asset retirement obligation liability ⁽⁵⁾	—	—	—	—	—	6,029	6,029
Operating leases	637	635	689	684	684	1,368	4,697
Vehicle loans	522	311	65	39	29	6	972
	\$111,190	\$126,069	\$117,729	\$106,496	\$103,189	\$1,403,007	\$1,967,680

- (1) The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 7 to our consolidated financial statements as of and for the year ended December 31, 2017.
- (2) We had contracts for the service of two rigs, which one expires in September 2018 and one expires in October 2018 both with the option to extend. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest, as applicable.
- (3) We have entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit us to transport minimum daily natural gas or NGL volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.
- (4) Contractual commitments for gas processing, gathering and compression service agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that we are committed to pay; however, we

will record in our financial statements our proportionate share of costs based on our working interest. Further, the values in the table do not include any commitments based on our amended agreement with Eureka Midstream contracted subsequent to year-end.

(5) Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

Other

We lease acreage that is generally subject to lease expiration if operations are not commenced within a specified period, generally 5 years and approximately 68% of our leases in the Utica Core Area have a 3-5 year extension at our option. Based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Interest Rates

At December 31, 2017 and December 31, 2016, we had \$510.5 million of senior unsecured notes outstanding, excluding discounts, which bore interest at a fixed cash interest rate of 8.875% and was due semi-annually from the date of issuance.

Information related to our interest rates is described in Note 7— Debt to our consolidated financial statements and is incorporated herein by reference.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments which are described above under “—Cash Contractual Obligations.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, it does not normally have a significant effect on our business. We expect costs in fiscal 2018 to continue to be a function of supply and demand. Further strengthening of commodity prices could stimulate demand for ancillary services causing services costs to increase. In the near term, the majority of our service costs are expected to remain flat in 2018 due to previously negotiated drilling, stimulation, and rentals contracts. Along with these contracts, we have secured quality service equipment and tenured personnel to limit our exposure to increasing service costs and improve operational efficiencies.

Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of

contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and proved natural gas and oil reserves. Some accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying

value of assets and liabilities that are not readily apparent from other sources. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Natural Gas and Oil Properties

We follow the successful efforts method of accounting for natural gas and oil producing activities. Unsuccessful exploration drilling costs are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are economically recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered 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. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, including the rule revisions designed to modernize the oil and gas company reserves reporting requirements which were adopted effective December 31, 2009, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Director, Reservoir Engineering who reports directly to our Chief Operating Officer. To further ensure the reliability of our reserve estimates, we engage independent petroleum engineers to prepare our estimates of proved reserves at least annually. NSAI, our independent petroleum engineers, prepared 100% of our reserves in 2017, 2016, 2015 and 2014. For additional discussion, see “Item 1. Business—Proved Reserves.”

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property’s total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to determine whether that property may be

impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 18—
Supplemental Oil and Gas Information to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in natural gas and oil properties in our consolidated balance sheets to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas, NGLs and oil prices, an estimate of the ultimate amount of recoverable natural gas, NGLs and oil reserves that will be produced from the property asset groups future production, future production costs, future abandonment costs, and future inflation. The need to test a property asset group for impairment can be based on several factors, including a significant reduction in sales prices for natural gas, NGLs and/or oil, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. Our natural gas and oil properties are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. All of these factors must be considered when testing a property asset groups carrying value for impairment.

The review is done by determining if the historical cost of proved and unproved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. The expected undiscounted future net cash flows are estimated based on our plans to produce and develop reserves. Expected undiscounted future net cash inflows from the sale of produced reserves are calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of undiscounted future cash flows. When the carrying value exceeds the sum of undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future.

We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leaseholds. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Potential impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors.

Acquisitions

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this

assessment is inherently uncertain.

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Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation (“ARO”), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment in formation, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Revenue Recognition

Natural gas, NGLs and oil sales are recognized when the products are sold and delivery to the purchaser has occurred. We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. We report our gathering and transportation costs in accordance with Financial Accounting Standards Board (“FASB”) Section 605-45-05 of Subtopic 605-45 for Revenue Recognition.

Under one type of agreement, we sell natural gas, NGLs or oil at a specific delivery point, pay transportation, gathering and compression to a third party and receive proceeds from the purchaser with no deduction. In that case, we record these costs as transportation, gatherings and compression expense. The other type of agreement is a netback arrangement under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we received from the purchaser. In the case of NGLs, we receive a net price from the purchaser (which is net of processing costs) which is recorded in revenue at the net price. Regardless of agreement type, revenue is recorded in the month the product is delivered to the purchaser as title has transferred.

To the extent we have not been paid for production related to a given reporting period, we record an accrual for revenue based on our estimate of the amount of production delivered to purchasers and the price we will receive, along with any related transportation costs. We estimate volumes delivered based on production information or from historical operating results of individual properties when production information is not available, for example, for certain non-operated properties. Prices for such production and related transportation costs are defined in sales contracts and are readily determinable based on publicly available indices. Given the information available to us, we do not believe there to be any material implications with respect to uncertainties in developing these estimates and historically, our actual receipts have not been materially different from our accruals. The purchasers of such production have historically made payment for oil, NGLs and natural gas purchases within 30-60 days of the end of each production month, at which time any variance between our estimated revenue and transportation costs and actual payments is recorded.

Recent Accounting Pronouncements

Information related to recent accounting pronouncements is described in Note 2— Summary of Significant Accounting Policies to our consolidated financial statements and is incorporated herein by reference.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 75% and 82% of our proved reserves as of December 31, 2017 and 2016, respectively, were natural gas.

For a discussion of how we use financial commodity derivative contracts to mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Commodity Hedging Activities.”

The following table shows the fair value of our commodity derivatives and the hypothetical change in fair value that would result from a 10% change in commodity prices at December 31, 2017:

	Fair Value	Hypothetical 10% Increase in Commodity Price	Hypothetical 10% Decrease in Commodity Price
Natural Gas	\$ 6,252	\$ (8,731)	\$ 7,055
NGLs	—	—	—
Oil	(11,320)	(7,720)	6,840

Interest Rate Risk

On July 6, 2015, we issued \$550 million in aggregate principal amount of 8.875% senior unsecured notes due 2023 at an issue price of 97.903% of the principal amount of the senior unsecured notes, plus accrued and unpaid interest, if any. At December 31, 2017, the cash interest rate with respect to the senior unsecured notes was fixed at 8.875% and was due semi-annually from the date of issuance.

We will be exposed to interest rate risk to the extent we draw on our revolving credit facility. Interest on outstanding borrowings under our revolving credit facility will accrue based on, at our option, LIBOR or the alternate base rate, in each case, plus an applicable margin that is determined based on our utilization of commitments under our revolving credit facility. As of December 31, 2017, the borrowing base was \$225 million and we had no outstanding borrowings. After giving effect to our outstanding letters of credit, totaling \$33.6 million, we had available borrowing capacity under the revolving credit facility of \$191.4 million at December 31, 2017. Subsequent to December 31, 2017, we borrowed \$45 million under our revolving credit facility, which reduced the available borrowing capacity under such facility to \$146.4 million.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts, the sale of our oil and gas production, which we market to energy companies, end users and refineries, and joint interest receivables.

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By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with seven counterparties. The fair value of our commodity derivative contracts of approximately (\$5.1) million at December 31, 2017 includes the following values by bank counterparty: Bank of Montreal (\$2.6) million; Citibank (\$0.2) million; KeyBank N.A. (\$6.6) million; Morgan Stanley \$1.7 million; Capital One N.A. (\$2.8) million; BP Energy Company (\$2.8) million; and Goldman Sachs \$8.2 million. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2017 for each of the banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our revolving credit facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2017, we did not have past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to concentration of our receivables from several significant customers for sales of natural gas. We, generally, do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required for this Item are set forth beginning on page F-1 of this report and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Company's management carried out an evaluation (as required by Rule 13a-15(b) of the Exchange Act), with the participation of the Company's President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act), as of the end of the period covered by this Annual Report. Based upon this evaluation, the Company's President and Chief Executive Officer and Executive Vice President and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this Annual Report, such that the information relating to the Company and its consolidated subsidiaries required to be disclosed by the Company in the reports that it files or submits under the Exchange Act (i) is recorded, processed, summarized, and reported, within the time periods specified in the SEC's rules and forms, and (ii) is accumulated and communicated to the Company's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15(d)-15(f) under the Exchange Act) during the fourth quarter of 2017 that has materially affected, or is reasonable likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system is designed to provide reasonable assurance to its management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Accordingly, even effective controls can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of its internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2017.

This Annual Report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

Item 9B. Other Information

Not applicable

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 14. Principal Accounting Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2018 Annual Meeting of Stockholders.

Item 15. Exhibits, Financial Statement Schedules

(1) Financial Statements:

The consolidated financial statements are listed on the Index to Financial Statements to this report beginning on page F-1 and incorporated herein by reference.

(2)Financial Statement Schedules:

No financial statement schedules are submitted because of the absence of the conditions under which they are required, the required information is insignificant or because the required information is included in the consolidated financial statements.

(3)Exhibits:

The following exhibits are filed as part of this Annual Report.

EXHIBIT INDEX

Exhibit No. Description

- 2.1# Purchase and Sale Agreement, dated December 8, 2017, between Travis Peak Resources, LLC, Eclipse Resources-PA, LP, and Eclipse Resources Corporation (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on December 12, 2017).

- 2.2# Option Agreement, dated as of December 8, 2017, by and among Cardinal Midstream II, LLC, Cardinal NE Holdings, LLC, Cardinal NE Midstream, LLC, Eclipse Resources Corporation, Eclipse Resources Midstream, LP, and Eclipse Resources-PA, LP (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K filed with the SEC on December 12, 2017).

- 2.3# Participation Agreement, dated December 22, 2017, by and among Eclipse Resources I, LP, Eclipse Resources-Ohio, LLC, and SEG-ECR LLC (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on December 28, 2017). +

- 3.1 Amended and Restated Certificate of Incorporation of Eclipse Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014).

- 3.2 Form of Amended and Restated Bylaws of Eclipse Resources Corporation (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014).

- 4.1 Stockholders Agreement, dated June 25, 2014, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., and Eclipse Management, L.P. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 30, 2014).

- 4.2 Amended and Restated Registration Rights Agreement, dated January 28, 2015, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Eclipse Management, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II (Luxembourg) S.à.r.l., Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 29, 2015).

- 4.3 Form of Common Stock Certificate of Eclipse Resources Corporation (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to the Company's Registration Statement on Form S-1 filed with the SEC on June 2, 2014).

- 4.4 Indenture, dated as of July 6, 2015, between Eclipse Resources Corporation, the guarantors party thereto and Deutsche Bank Trust Company Americas, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on July 8, 2015).

- 4.5 Registration Rights Agreement, dated as of January 18, 2018, by and among Eclipse Resources Corporation, Eclipse Resources-PA, LP, and Travis Peak Resources, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 22, 2018).
- 10.1 Second Amended and Restated Credit Agreement, dated as of June 11, 2015, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 12, 2015).

Exhibit No. Description

- 10.2 First Amendment to Second Amended and Restated Credit Agreement, dated January 21, 2016, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 25, 2016).
- 10.3 Second Amendment to Second Amended and Restated Credit Agreement, dated as of February 24, 2016, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on February 26, 2016).
- 10.4 Third Amendment to Second Amended and Restated Credit Agreement, dated as of February 24, 2017, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2017).
- 10.5 Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of August 1, 2017, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 7, 2017).
- 10.6† Eclipse Resources Corporation 2014 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014).
- 10.7† Eclipse Resources Corporation 2014 Long-Term Incentive Plan, as amended by the First Amendment (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on May 18, 2017).
- 10.8 Master Reorganization Agreement, dated June 6, 2014, by and among Eclipse Resources I, LP, Eclipse GP, LLC, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., Eclipse Management, L.P., Eclipse Resources Holdings, L.P., Eclipse Resources Corporation and Benjamin W. Hulburt, Christopher K. Hulburt and Thomas S. Liberatore (incorporated by reference to Exhibit 10.9 to Amendment No. 2 to the Company's Registration Statement on Form S-1 filed with the SEC on June 9, 2014).
- 10.9† Form of Indemnification Agreement for Eclipse Resources Corporation Officers and Directors (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to the Company's Registration Statement on Form S-1 filed with the SEC on June 2, 2014).
- 10.10† Amended and Restated Executive Employment Agreement, dated as of August 17, 2017, by and between Eclipse Resources Corporation and Benjamin W. Hulburt (incorporated by referenced to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 18, 2017).
- 10.11† Amended and Restated Executive Employment Agreement, dated as of August 17, 2017, by and between Eclipse Resources Corporation and Matthew R. DeNezza (incorporated by referenced to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on August 18, 2017).

- 10.12† Amended and Restated Executive Employment Agreement, dated as of August 17, 2017, by and between Eclipse Resources Corporation and Christopher K. Hulburt (incorporated by referenced to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on August 18, 2017).
- 10.13† Amended and Restated Executive Employment Agreement, dated as of January 1, 2017, by and between Eclipse Resources Corporation and Oleg Tolmachev (incorporated by referenced to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 3, 2017).

Exhibit No. Description

- 10.14 Securities Purchase Agreement, dated as of December 27, 2014, by and between Eclipse Resources Corporation, CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II L.P., GSO Eclipse Holdings I LP, Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on December 29, 2014).
- 10.15† Form of Restricted Stock Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2016).
- 10.16† Form of Performance Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2016).
- 10.17† Form of Restricted Stock Unit Award Agreement for 2015 Bonuses (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on March 2, 2016).
- 10.18† Form of Performance Stock Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on April 26, 2016).
- 21.1* List of Subsidiaries of Eclipse Resources Corporation
- 23.1* Consent of Grant Thornton LLP
- 23.2* Consent of Netherland, Sewell & Associates, Inc.
- 31.1* Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241)
- 31.2* Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241)
- 32.1** Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350)
- 32.2** Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350)
- 99.1* Netherland Sewell & Associates, Inc., Summary of Reserves for Unconventional Properties as of December 31, 2017 (Eclipse Resources Corporation).
- 99.2 Netherland Sewell & Associates, Inc., Summary of Reserves for Unconventional Properties as of December 31, 2016 (Eclipse Resources Corporation) (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017).
- 99.3 Netherland Sewell & Associates, Inc., Summary of Reserves for Unconventional Properties as of December 31, 2015 (Eclipse Resources Corporation) (incorporated by reference to Exhibit 99.1 to the

Company's Annual Report on Form 10-K filed with the SEC on March 4, 2016).

- 99.4 Netherland Sewell & Associates, Inc., Summary of Reserves for Conventional Properties as of December 31, 2015 (Eclipse Resources Corporation) (incorporated by reference to Exhibit 99.2 to the Company's Annual Report on Form 10-K filed with the SEC on March 4, 2016).

Exhibit No. Description

101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

#Pursuant to Item 601(b)(2) of Regulation S-K, certain schedules and similar attachments to this agreement have been omitted. The registrant hereby agrees to furnish supplementally a copy of any omitted schedule or similar attachment to the Securities and Exchange Commission upon request.

*Filed herewith.

** These exhibits are furnished herewith and shall not be deemed “filed” for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act.

+Confidential treatment has been granted for certain portions of this Exhibit pursuant to Rule 24b-2 of the Exchange Act, which portions have been omitted and filed separately with the Securities and Exchange Commission.

Management contract or compensatory plan or arrangement.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized

March 2, 2018 ECLIPSE RESOURCES CORPORATION

(Registrant)

/s/ Benjamin W. Hulburt
Benjamin W. Hulburt

Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signature	Date
/s/ Benjamin W. Hulburt Benjamin W. Hulburt	March 2, 2018
Chairman, President and Chief Executive Officer	
/s/ Matthew R. DeNezza Matthew R. DeNezza	March 2, 2018
Executive Vice President and Chief Financial Officer	
/s/ Roy S. Steward Roy S. Steward	March 2, 2018
Senior Vice President and Chief Accounting Officer	
/s/ Christopher K. Hulburt Christopher K. Hulburt	March 2, 2018
Director, Executive Vice President, Secretary and General Counsel	
/s/ D. Martin Phillips D. Martin Phillips	March 2, 2018
Director	

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/s/ Robert L. Zorich
Robert L. Zorich

March 2, 2018

Director

/s/ Douglas E. Swanson, Jr.
Douglas E. Swanson, Jr.

March 2, 2018

Director

/s/ Mark E. Burroughs, Jr.
Mark E. Burroughs, Jr.

March 2, 2018

Director

/s/ Joseph C. Winkler, III
Joseph C. Winkler, III

March 2, 2018

Director

/s/ Richard Paterson
Richard Paterson

March 2, 2018

Director

/s/ Randall M. Albert
Randall M. Albert

March 2, 2018

Director

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Eclipse Resources Corporation

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Eclipse Resources Corporation (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2017 and 2016, the related consolidated statements of comprehensive income, changes in stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2011.

Pittsburgh, PA

March 2, 2018

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ECLIPSE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share data)

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 17,224	\$ 201,229
Accounts receivable	77,609	44,423
Assets held for sale	206	468
Other current assets	12,023	4,295
Total current assets	107,062	250,415
PROPERTY AND EQUIPMENT AT COST		
Oil and natural gas properties, successful efforts method:		
Unproved properties	459,549	526,270
Proved oil and gas properties, net	647,881	414,482
Other property and equipment, net	6,942	6,748
Total property and equipment, net	1,114,372	947,500
OTHER NONCURRENT ASSETS		
Other assets	2,093	729
TOTAL ASSETS	\$ 1,223,527	\$ 1,198,644
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	\$ 76,174	\$ 44,049
Accrued capital expenditures	10,658	11,083
Accrued liabilities	41,662	55,044
Accrued interest payable	21,100	21,098
Liabilities held for sale	—	245
Total current liabilities	149,594	131,519
NONCURRENT LIABILITIES		
Debt, net of unamortized discount and debt issuance costs	495,021	492,278
Asset retirement obligations	6,029	4,806
Other liabilities	529	13,434
Total liabilities	651,173	642,037
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock, 50,000,000 authorized, no shares issued and outstanding	—	—
Common stock, \$0.01 par value, 1,000,000,000 authorized, 262,740,355	2,637	2,607

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and 260,591,893 shares issued and outstanding, respectively		
Additional paid in capital	1,967,958	1,958,731
Treasury stock, shares at cost; 992,315 and 72,704 shares, respectively	(2,096)	(61)
Accumulated deficit	(1,396,145)	(1,404,670)
Total stockholders' equity	572,354	556,607
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 1,223,527	\$ 1,198,644

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

ECLIPSE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands except per share data)

	For the Year Ended December 31,		
	2017	2016	2015
REVENUES			
Natural gas, oil and natural gas liquids sales	\$380,178	\$223,015	\$234,601
Brokered natural gas and marketing revenue	3,481	12,019	20,720
Total revenues	383,659	235,034	255,321
OPERATING EXPENSES			
Lease operating	20,525	9,023	13,904
Transportation, gathering and compression	124,839	109,226	85,846
Production and ad valorem taxes	8,490	7,927	3,722
Brokered natural gas and marketing expense	3,191	12,268	26,173
Depreciation, depletion and amortization	118,818	92,948	244,750
Exploration	50,208	52,775	116,211
General and administrative	44,553	39,431	46,409
Rig termination and standby	1	3,846	9,672
Impairment of proved oil and gas properties	—	17,665	691,334
Accretion of asset retirement obligations	544	391	1,623
(Gain) loss on sale of assets	(179)	6,936	(4,737)
Total operating expenses	370,990	352,436	1,234,907
OPERATING INCOME (LOSS)	12,669	(117,402)	(979,586)
OTHER INCOME (EXPENSE)			
Gain (loss) on derivative instruments	45,365	(52,338)	56,021
Interest expense, net	(49,490)	(50,789)	(53,400)
Gain (loss) on early extinguishment of debt	—	14,489	(59,392)
Other income (expense)	(19)	(149)	400
Total other income (expense), net	(4,144)	(88,787)	(56,371)
INCOME (LOSS) BEFORE INCOME TAXES	8,525	(206,189)	(1,035,957)
INCOME TAX BENEFIT (EXPENSE)	—	(546)	74,166
NET INCOME (LOSS)	\$8,525	\$(206,735)	\$(961,791)
NET INCOME (LOSS) PER COMMON SHARE			
Basic	\$0.03	\$(0.86)	\$(4.41)
Diluted	\$0.03	\$(0.86)	\$(4.41)
WEIGHTED AVERAGE COMMON SHARES			
OUTSTANDING			
Basic	262,181	241,434	217,897
Diluted	265,182	241,434	217,897

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

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ECLIPSE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	For the Year Ended December		
	31,		
	2017	2016	2015
NET INCOME (LOSS)	\$8,525	\$(206,735)	\$(961,791)
Other comprehensive income (loss):			
Pension obligation adjustment, net of tax	—	—	548
TOTAL COMPREHENSIVE GAIN (LOSS)	\$8,525	\$(206,735)	\$(961,243)

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

ECLIPSE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, and 2015

(in thousands, except share and per share data)

	Number of Shares	Common Stock (\$0.01 Par)	Additional Paid-in- Capital	Treasury Stock	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total
Balances, December 31,							
2014	160,031,115	\$ 1,600	\$ 1,391,004	\$ —	\$ (236,144)	\$ (548)	\$ 1,155,912
Stock-based compensation	—	—	4,635	—	—	—	4,635
Shares of common stock							
issued in initial public offering, net of costs	62,500,000	625	433,445	—	—	—	434,070
Issuance of restricted stock	132,496	1	(1)	—	—	—	—
Issuance of common stock							
upon vesting of equity- based compensation awards, net of shares withheld for income tax withholdings	10,659	1	(1)	—	—	—	—
Pension obligation adjustment	—	—	—	—	—	548	548
Net loss	—	—	—	—	(961,791)	—	(961,791)
Balances, December 31,	222,674,270	\$ 2,227	\$ 1,829,082	\$ —	\$ (1,197,935)	\$ —	\$ 633,374

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2015							
Stock-based compensation	—	—	6,216	—	—	—	6,216
Shares of common stock							
issued in public offering,							
net of equity issuance costs	37,500,000	375	123,438	—	—	—	123,813
Issuance of restricted stock	149,448	2	(2)	—	—	—	—
Issuance of common stock							
upon vesting of equity-							
based compensation							
awards, net of shares							
withheld for income							
tax withholdings	268,175	3	(3)	(61)	—	—	(61)
Net loss	—	—	—	—	(206,735)	—	(206,735)
Balances, December 31,							
2016	260,591,893	\$ 2,607	\$ 1,958,731	\$(61)	\$(1,404,670)	\$ —	\$556,607
Stock-based compensation	—	—	9,301	—	—	—	9,301
Equity issuance costs	—	—	(44)	—	—	—	(44)
Issuance of restricted stock	153,192	2	(2)	—	—	—	—
Issuance of common stock							
upon vesting of equity-							
based compensation							
awards, net of shares							
withheld for income							
tax withholdings	1,995,270	28	(28)	(2,035)	—	—	(2,035)
Net income	—	—	—	—	8,525	—	8,525
Balances, December 31,	262,740,355	\$ 2,637	\$ 1,967,958	\$(2,096)	\$(1,396,145)	\$ —	\$572,354

2017

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

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ECLIPSE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	For the Year Ended		
	December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	\$8,525	\$(206,735)	\$(961,791)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation, depletion and amortization	118,818	92,948	244,750
Exploration expense	31,417	30,853	95,849
Pension benefit costs	—	—	259
Stock-based compensation	9,301	6,216	4,635
Impairment of proved oil and gas properties	—	17,665	691,334
Accretion of asset retirement obligations	544	391	1,623
(Gain) loss on derivative instruments	(45,365)	52,338	(56,021)
Net cash receipts (payments) on settled derivatives	(2,224)	38,696	37,074
(Gain) loss on sale of assets	(179)	6,936	(4,737)
(Gain) loss on sale of business	—	—	(400)
(Gain) loss on early extinguishment of debt	—	(14,489)	59,392
Deferred income taxes	—	540	(74,481)
Interest not paid in cash	—	—	1,232
Amortization of deferred financing costs	2,098	1,962	1,991
Amortization of debt discount	1,324	1,362	1,886
Changes in operating assets and liabilities:			
Accounts receivable	(31,780)	(21,277)	20,209
Other assets	1,863	(1,795)	445
Accounts payable and accrued liabilities	18,404	794	17,050
Net cash provided by operating activities	112,746	6,405	80,299
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures for oil and gas properties	(291,779)	(167,355)	(475,659)
Capital expenditures for other property and equipment	(2,007)	(1,164)	(1,748)
Proceeds from sale of assets	1,317	79,201	40,139
Net cash used in investing activities	(292,469)	(89,318)	(437,268)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from issuance of long-term debt	—	—	538,466
Debt issuance costs	(1,750)	30	(13,362)
Repayments of long-term debt	(453)	(24,045)	(485,317)
Proceeds from issuance of common stock	—	124,361	440,000
Equity issuance costs	(44)	(548)	(5,930)
Employee tax withholding for settlement of equity compensation awards	(2,035)	(61)	—

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Net cash provided by (used in) financing activities	(4,282)	99,737	473,857
Net decrease in cash and cash equivalents	(184,005)	16,824	116,888
Cash and cash equivalents at beginning of period	201,229	184,405	67,517
Cash and cash equivalents at end of period	\$17,224	\$201,229	\$184,405

SUPPLEMENTAL DISCLOSURE OF CASH FLOW

INFORMATION

Cash paid for interest	\$47,362	\$48,483	\$39,808
Cash paid for income taxes	\$—	\$—	\$505

SUPPLEMENTAL DISCLOSURE OF NON-CASH

ACTIVITIES

Asset retirement obligations incurred, including changes in

estimate	\$679	\$1,014	\$3,435
Additions of other property through debt financing	\$183	\$—	\$888
Additions to oil and natural gas properties - changes in			

accounts payable, accrued liabilities, and

accrued capital expenditures	\$22,264	\$8,583	\$(142,665)
Assets held for sale	\$(262)	\$—	\$(35,289)
Interest paid-in-kind	\$—	\$—	\$14,786

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

ECLIPSE RESOURCES CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, and 2015

Note 1—Organization and Nature of Operations

Eclipse Resources Corporation (the “Company”), is an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin of the United States, which encompasses the Utica Shale and Marcellus Shale prospective areas.

Note 2—Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”). In the opinion of management, the accompanying consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company’s financial position as of December 31, 2017 and 2016, and the results of its operations, comprehensive income (loss) and its cash flows for the years ended December 31, 2017, 2016, and 2015.

(b) Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash in banks and highly liquid instruments with original maturities of three months or less, primarily consisting of bank time deposits and investments in institutional money market funds. The carrying amounts approximate fair value due to the short-term nature of these items. Cash in bank accounts at times may exceed federally insured limits.

(c) Accounts Receivable

Accounts receivable are carried at estimated net realizable value. Receivables deemed uncollectible are charged directly to expense. Trade credit is generally extended on a short-term basis, and therefore, accounts receivable do not bear interest, although a finance charge may be applied to such receivables that are past due. A valuation allowance is provided for those accounts for which collection is estimated as doubtful and uncollectible accounts are written off and charged against the allowance. In estimating the allowance, management considers, among other things, how recently and how frequently payments have been received and the financial position of the party. The Company did not deem any of its accounts receivables to be uncollectable as of December 31, 2017 or December 31, 2016.

The Company accrues revenue due to timing differences between the delivery of natural gas, natural gas liquids (NGLs), and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Company's records and management's estimates of the related commodity sales and transportation and compression fees, which are, in turn, based upon applicable product prices. The Company had \$52.9 million and \$41.4 million of accrued revenues, net of expenses at December 31, 2017 and December 31, 2016, respectively, which were included in accounts receivable within the Company's consolidated balance sheets.

(d) Property and Equipment

Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for its oil and natural gas operations. Acquisition costs for oil and natural gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense (see " Depreciation, Depletion and Amortization " below).

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Costs incurred to acquire producing and non-producing leaseholds are capitalized. All unproved leasehold acquisition costs are initially capitalized, including the cost of leasing agents, title work and due diligence. If the Company acquires leases in a prospective area, these costs are capitalized as unproved leasehold costs. If no leases are acquired by the Company with respect to the initial costs incurred or the Company discontinues leasing in a prospective area, the costs are charged to exploration expense. Unproved leasehold costs that are determined to have proved oil and gas reserves are transferred to proved leasehold costs.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Company's consolidated statements of operations. Upon the sale of an individual well, the proceeds are credited to accumulated depreciation and depletion within the Company's consolidated balance sheets. Upon the sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the Company's consolidated statements of operations. Upon the sale of an entire interest in an unproved property where the property had been assessed for impairment on a group basis, no gain or loss is recognized in the Company's consolidated statements of operations unless the proceeds exceed the original cost of the property, in which case a gain is recognized in the amount of such excess. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

A summary of property and equipment including oil and natural gas properties is as follows (in thousands):

	December 31, 2017	December 31, 2016
Oil and natural gas properties:		
Unproved	\$ 459,549	\$ 526,270
Proved	1,896,081	1,545,860
Gross oil and natural gas properties	2,355,630	2,072,130
Less accumulated depreciation, depletion and amortization	(1,248,200)	(1,131,378)
Oil and natural gas properties, net	1,107,430	940,752
Other property and equipment	13,508	11,447
Less accumulated depreciation	(6,566)	(4,699)
Other property and equipment, net	6,942	6,748
Property and equipment, net	\$ 1,114,372	\$ 947,500

Exploration expenses, including geological and geophysical expenses and delay rentals for unevaluated oil and gas properties are charged to expense as incurred. Exploratory drilling costs are initially capitalized as unproved property, not subject to depletion, but charged to expense if and when the well is determined not to have found proved oil and gas reserves.

The Company capitalized interest expense totaling \$2.3 million, \$1.1 million and \$2.8 million for the years ended December 31, 2017, 2016, and 2015, respectively.

Other Property and Equipment

Other property and equipment include land, buildings, leasehold improvements, vehicles, computer equipment and software, telecommunications equipment, and furniture and fixtures. These items are recorded at cost, or fair value if acquired through a business acquisition.

(e) Accrued Liabilities

A summary of accrued liabilities is as follows (in thousands):

	December 31, 2017	December 31, 2016
Ad valorem and production taxes	\$ 4,299	\$ 4,519
Employee compensation	8,667	4,257
Royalties	9,660	8,557
Short term derivatives	14,876	35,409
Other	4,160	2,302
Total accrued liabilities	\$ 41,662	\$ 55,044

(f) Revenue Recognition

Oil and natural gas sales revenue is recognized when produced quantities of oil and natural gas are delivered to a custody transfer point such as a pipeline, processing facility or a tank lifting has occurred, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sales is reasonably assured and the sales price is fixed or determinable. Revenues from the sales of natural gas, crude oil or NGLs in which the Company has an interest with other producers are recognized using the sales method on the basis of the Company's net revenue interest. The Company had no material imbalances as of December 31, 2017 and December 31, 2016.

In accordance with the terms of joint operating agreements, from time to time, the Company may be paid monthly fees for operating or drilling wells for outside owners. The fees are meant to recoup some of the operator's general and administrative costs in connection with well and drilling operations and are accounted for as credits to general and administrative expense.

Brokered natural gas and marketing revenues include revenues from brokered gas or revenue the Company receives as a result of selling and buying natural gas that is not related to its production and revenue from the release of transportation capacity. The Company realizes brokered margins as a result of buying and selling natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby the Company or the counterparty takes title to the natural gas purchased or sold. Revenues and expenses related to brokering natural gas are reported gross as part of revenue and expense in accordance with U.S. GAAP. The Company considers these activities as ancillary to its natural gas sales and thus report them within one operating segment.

(g) Major Customers

The Company sells production volumes to various purchasers. For the years ended December 31, 2017, 2016, and 2015, there were two, four and four customers, respectively, that accounted for 10% or more of the total natural gas, NGLs and oil sales. The following table sets forth the Company's major customers and associated percentage of revenue for the periods indicated:

For the Year Ended
December 31,
2017 2016 2015

Purchaser				
Antero Resources Corporation	—	14 %	19 %	
ARM Energy Management	—	—	11 %	
Concord Energy, LLC	—	12 %	—	
Emera Energy Services	17 %	—	—	
EnLink Midstream Operating	—	17 %	21 %	
Marathon Petroleum	10 %	—	—	
Sequent Energy Management	—	20 %	19 %	
Total	27 %	63 %	70 %	

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Management believes that the loss of any one customer would not have a material adverse effect on the Company's ability to sell natural gas, NGLs and oil production because it believes that there are potential alternative purchasers although it may be necessary to establish relationships with new purchasers. However, there can be no assurance that the Company can establish such relationships or that those relationships will result in an increased number of purchasers.

(h) Concentration of Credit Risk

The following table summarizes concentration of receivables, net of allowances, by product or service as of December 31, 2017 and December 31, 2016 (in thousands):

	December 31, 2017	December 31, 2016
Receivables by product or service:		
Sale of oil and natural gas and related products		
and services	\$ 52,908	\$ 41,398
Joint interest owners	23,154	2,850
Derivatives	1,528	122
Other	19	53
Total	\$ 77,609	\$ 44,423

Oil and natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the State of Ohio. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, the Company exposes itself to the credit risk of counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. The fair value of the Company's commodity unsettled derivative contracts was a net liability position of (\$5.1) million and (\$48.1) million at December 31, 2017 and 2016, respectively. Other than, as provided by the revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under the Company's contracts, nor are they required to provide credit support to the Company. As of December 31, 2017, the Company did not have past-due receivables from or payables to any of the counterparties.

(i) Depreciation, Depletion and Amortization

Oil and Natural Gas Properties

Depreciation, depletion, and amortization ("DD&A") of capitalized costs of proved oil and natural gas properties is computed using the unit-of-production method on a field level basis using total estimated proved reserves. The reserve

base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate DD&A for drilling, completion and well equipment costs, which include development costs and successful exploration drilling costs, includes only proved developed reserves. DD&A expense relating to proved oil and natural gas properties for the years ended December 31, 2017, 2016, and 2015 totaled approximately \$116.8 million, \$91.0 million and \$242.9 million, respectively.

Other Property and Equipment

Depreciation with respect to other property and equipment is calculated using straight-line methods based on expected lives of the individual assets or groups of assets ranging from 5 to 40 years. Depreciation for the years

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ended December 31, 2017, 2016, and 2015 totaled approximately \$2.0 million, \$1.9 million and \$1.8 million, respectively. This amount is included in DD&A expense in the consolidated statements of operations.

(j) Impairment of Long-Lived Assets

The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

The review of the Company's oil and gas properties is done by determining if the historical cost of proved and unproved properties less the applicable accumulated DD&A and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Company's plans to continue to produce and develop proved reserves and a risk-adjusted portion of probable reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. The Company estimates prices based upon current contracts in place, adjusted for basis differentials and market-related information, including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. As a result of the decline in commodity prices, the Company recognized impairment expenses of approximately \$17.7 million for the year ended December 31, 2016 relating to proved properties in the Marcellus Shale and \$691.3 million for the year ended December 31, 2015 relating to proved properties in the Utica Shale.

The aforementioned impairment charges represented a significant Level 3 measurement in the fair value hierarchy. The primary input used was the Company's forecasted discount net cash flows.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the properties. An impairment charge is recorded if conditions indicate the Company will not explore the acreage prior to expiration of the applicable leases. The Company recorded impairment charges of unproved oil and gas properties related to lease expirations of \$28.3 million, \$29.8 million, and \$95.6 million for the years ended December 31, 2017, 2016, and 2015, respectively. These costs are included in exploration expense in the consolidated statements of operations.

(k) Income Taxes

The Company accounts for income taxes, as required, under the liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is

more likely than not that some portion or all of the deferred tax assets will not be realized.

ASC Topic 740 “ Income Taxes ” provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. Income tax positions must meet a more-likely-

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than-not recognition threshold at the effective date to be recognized upon the adoption of the uncertain tax position guidance and in subsequent periods. This interpretation also provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company has not recorded a reserve for any uncertain tax positions to date.

(l) Fair Value of Financial Instruments

The Company has established a hierarchy to measure its financial instruments at fair value, which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 —Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 —Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

Level 3 —Unobservable inputs that reflect the entity's own assumptions about the assumption market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

(m) Derivative Financial Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of the energy commodities it sells.

Derivatives are recorded at fair value and are included on the consolidated balance sheets as current and noncurrent assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual expiration date. Derivatives with expiration dates within the next 12 months are classified as current. The Company netted the fair value of derivatives by counterparty in the accompanying consolidated balance sheets where the right to offset exists. The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities. Premiums for options are included in cash flows from operating activities.

The valuation of the Company's derivative financial instruments represents a Level 2 measurement in the fair value hierarchy.

(n) Asset Retirement Obligation

The Company recognizes a legal liability for its asset retirement obligations (“ARO”) in accordance with Topic ASC 410, “Asset Retirement and Environmental Obligations,” associated with the retirement of a tangible long-lived asset, in the period in which it is incurred or becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The Company measures the fair value of its ARO using expected future cash outflows for abandonment discounted back to the date that the abandonment obligation

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was measured using an estimated credit adjusted rate, which was 10.33% for the years ended December 31, 2017 and 2016, respectively.

Estimating the future ARO requires management to make estimates and judgments based on historical estimates regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

The following table sets forth the changes in the Company's ARO liability for the period indicated (in thousands):

	Year Ended		
	December 31, 2017	December 31, 2016	December 31, 2015
Asset retirement obligations, beginning of period	\$4,806	\$ 3,401	\$ 17,400
Liabilities associated with assets held for sale	—	—	(19,057)
Revisions of prior estimates	—	—	2,913
Additional liabilities incurred	679	1,014	522
Accretion	544	391	1,623
Asset retirement obligations, end of period	\$6,029	\$ 4,806	\$ 3,401

The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to ARO represent a significant nonrecurring Level 3 measurement.

(o) Lease Obligations

The Company leases office space under an operating lease that expires in 2024. The lease terms begin on the date of initial possession of the leased property for purposes of recognizing lease expense on a straight-line basis over the term of the lease. The Company does not assume renewals in its determination of the lease terms unless the renewals are deemed to be reasonably assured at lease inception.

(p) Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements.

(q) Segment Reporting

The Company operates in one industry segment: the oil and natural gas exploration and production industry in the United States. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

(r) Debt Issuance Costs

The expenditures related to issuing debt are capitalized and reported as a reduction of the Company's debt balance in the accompanying balance sheets. These costs are amortized over the expected life of the related instruments using the effective interest rate method. When debt is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed.

(s) Recent Accounting Pronouncements

The FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)" ("Update 2014-09"), which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue

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Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, “Property, Plant and Equipment”, and intangible assets within the scope of Topic 350, “Intangibles—Goodwill and Other”) are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to 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. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period with early adoption permitted.

The Company will adopt this standard effective January 1, 2018 using the modified retrospective method. During 2017, the Company finalized the detailed analysis of the impact of the standard on its contracts. The Company found that there was no significant impact on its financial position or results of operations. Upon adoption of this Accounting Standards Update, the Company will not be required to record a cumulative effect adjustment due to the new Accounting Standards Update not having a quantitative impact compared to existing GAAP. Also, upon adoption of this Accounting Standards Update, the Company will not be required to alter its existing information technology and internal controls outside of ongoing contract review processes in order to identify impacts of future revenue contracts entered into by the Company. The Company does not anticipate the disclosure requirements under the Accounting Standards update to have a material change on how it presents information regarding its revenue streams as compared to existing GAAP.

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” The new standard provides guidance to increase transparency and comparability among organizations and industries by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. An entity will be required to recognize all leases in the statement of financial position as assets and liabilities regardless of the leases classification. These requirements are effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period with early adoption permitted. The Company is evaluating the impact of the adoption on its financial position, results of operations and related disclosures as well as monitoring relevant industry guidance regarding implementation of the standard and adjust its implementation strategies as necessary.

In August 2016, the FASB issued ASU 2016-15, “Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments.” The new standard provides guidance on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. These requirements are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. The Company is evaluating the impact of the adoption on its statement of cash flows and related disclosures.

In January 2017, the FASB issued ASU 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business.” Currently under the standard there are three elements of a business: inputs, processes and outputs. The revised guidance adds an initial screen test to determine if substantially all of the fair value of the gross assets acquired is concentrated in a single asset or group of similar assets. If that screen is met, the set of assets is not a business. The new framework also specifies the minimum required inputs and processes necessary to be a business. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is evaluating the impact of the adoption on its statement of cash flows and related disclosures.

(t) Change in Estimates

During the year ended December 31, 2016, the Company reduced its estimate of amounts due from a non-operated partner related to the sale of natural gas and NGLs, net of associated costs, based on revised information received from the non-operated partner during the period. As a result, the Company decreased accounts receivable by approximately \$4 million, increased revenue from oil and natural gas sales by approximately \$1.5 million, and increased transportation, gathering and compression expense by approximately \$5.8 million, which increased the net loss for the year ended December 31, 2016 by approximately \$4 million, or \$0.02 per common share.

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During the year ended December 31, 2016, the Company reduced its estimate for production and ad valorem tax expense based on recent historical experience and additional information received during the period. As a result, the Company decreased the accrual for production and ad valorem taxes to be paid by approximately \$4 million, which decreased the net loss for the year ended December 31, 2016 by a corresponding amount, or \$0.02 per common share.

(u) Correction of Immaterial Error

During the three months ended March 31, 2017, the Company determined that its estimated accrual for production and ad valorem tax expense was overstated for prior periods. The Company evaluated the materiality of this error on both a quantitative and qualitative basis under the guidance of ASC 250 "Accounting Changes and Errors Corrections," and determined that it did not have a material impact to previously issued financial statements.

Although the error was immaterial to prior periods, the prior period financial statements were revised, in accordance with SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, due to the significance of the out-of-period correction to the current period. Immaterial errors related to periods prior to the year ended December 31, 2016 are reflected as an adjustment to beginning accumulated deficit for that year. Periods not presented herein will be revised, as applicable, in future filings.

A reconciliation of the effects of the revision to amounts in the previously reported consolidated financial statements is as follows (in thousands, except per share amounts):

	As of December 31, 2016		
	As		
	Reported	Adjustment	As Adjusted
Balance Sheet			
Accounts receivable	\$43,638	\$ 785	\$44,423
Total current assets	249,630	785	250,415
Total assets	1,197,859	785	1,198,644
Accrued liabilities	64,150	(9,106)	55,044
Total current liabilities	140,625	(9,106)	131,519
Total liabilities	651,143	(9,106)	642,037
Accumulated deficit	(1,414,561)	9,891	(1,404,670)
Total stockholders' equity	546,716	9,891	556,607
Total liabilities and stockholders' equity	1,197,859	785	1,198,644

	As of December 31, 2016		
	As		
	Reported	Adjustment	As Adjusted
Statement of Stockholders' Equity			
Accumulated deficit	\$(1,414,561)	\$ 9,891	\$(1,404,670)
Total stockholders' equity	546,716	9,891	556,607

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	As of December 31, 2015		
	As		
	Reported	Adjustment	As Adjusted
Balance Sheet			
Accounts receivable	\$27,476	\$ 253	\$27,729
Total current assets	269,384	253	269,637
Total assets	1,266,412	253	1,266,665
Accounts payable	34,717	2,137	36,854
Accrued liabilities	25,462	(14,704)	10,758
Total current liabilities	113,842	(12,567)	101,275
Total liabilities	645,858	(12,567)	633,291
Accumulated deficit	(1,210,755)	12,820	(1,197,935)
Total stockholders' equity	620,554	12,820	633,374
Total liabilities and stockholders' equity	1,266,412	253	1,266,665

	As of December 31, 2015		
	As		
	Reported	Adjustment	As Adjusted
Statement of Stockholders' Equity			
Accumulated deficit	\$(1,210,755)	\$ 12,820	\$(1,197,935)
Total stockholders' equity	620,554	12,820	633,374

	As of December 31, 2014		
	As		
	Reported	Adjustment	As Adjusted
Statement of Stockholders' Equity			
Accumulated deficit	\$(239,345)	\$ 3,201	\$(236,144)
Total stockholders' equity	1,152,711	3,201	1,155,912

	As of December 31, 2016		
	As		
	Reported	Adjustment	As Adjusted
Statement of Operations			
Production and ad valorem taxes	\$4,998	\$ 2,929	\$7,927
Total operating expenses	349,507	2,929	352,436
Operating loss	(114,473)	(2,929)	(117,402)
Loss before income taxes	(203,260)	(2,929)	(206,189)
Net loss	(203,806)	(2,929)	(206,735)
Basic and diluted loss per share	\$(0.84)	\$ (0.02)	\$(0.86)

	As of December 31, 2015		
	As		
	Reported	Adjustment	As Adjusted

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Statement of Operations			
Production and ad valorem taxes	\$ 11,621	\$ (7,899)	\$ 3,722
Total operating expenses	1,242,806	(7,899)	1,234,907
Operating loss	(987,485)	7,899	(979,586)
Loss before income taxes	(1,043,856)	7,899	(1,035,957)
Income tax benefit (expense)	72,446	1,720	74,166
Net loss	(971,410)	9,619	(961,791)
Basic and diluted loss per share	\$(4.46)	\$ 0.05	\$(4.41)

As of December 31, 2016

As	As
Reported	Adjusted

Statement of Comprehensive Loss			
Net loss	\$(203,806)	\$ (2,929)	\$(206,735)
Total Comprehensive loss	(203,806)	(2,929)	(206,735)

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	As of December 31, 2015		
	As Reported	Adjustment	As Adjusted
Statement of Comprehensive Loss			
Net loss	\$(971,410)	\$ 9,619	\$(961,791)
Total Comprehensive loss	(970,862)	9,619	(961,243)

	As of December 31, 2016		
	As Reported	Adjustment	As Adjusted
Statement of Cash Flows			
Net loss	\$(203,806)	\$ (2,929)	\$(206,735)
Accounts receivable	(20,563)	(714)	(21,277)
Accounts payable and accrued liabilities	(2,849)	3,643	794

	As of December 31, 2015		
	As Reported	Adjustment	As Adjusted
Statement of Cash Flows			
Net loss	\$(971,410)	\$ 9,619	\$(961,791)
Deferred income taxes	(72,761)	(1,720)	(74,481)
Accounts receivable	20,437	(228)	20,209
Accounts payable and accrued liabilities	24,721	(7,671)	17,050

Note 3—Acquisition

Eclipse Resources-PA, LP Acquisition

On January 18, 2018, the Company completed the purchase of approximately 44,500 net acres in Tioga and Potter Counties, Pennsylvania for an aggregate adjusted purchase price of \$92.2 million, which was paid in approximately 37.8 million shares of common stock to Travis Peak Resources, LLC.

Note 4—Sale of Oil and Natural Gas Property Interests

Asset Sales

During the year ended December 31, 2015, the Company sold a central processing facility and certain pipelines. The transaction resulted in proceeds of \$36.0 million and a gain on sale of assets of \$4.8 million, which was recorded during the year ended December 31, 2014. These assets were classified as assets held for sale as of December 31, 2014.

Additional pipeline assets were sold during the year ended December 31, 2015, which resulted in proceeds of approximately \$2.8 million and a loss on sale of assets of approximately \$0.1 million.

During the year ended December 31, 2016, the Company completed the sale of its Conventional oil and gas properties and related equipment for approximately \$4.7 million. As of December 31, 2015, the Company was actively negotiating the sale of these assets and the costs related to these properties of approximately \$21.8 million and corresponding asset retirement obligations of approximately \$19.1 million were classified as held for sale in the consolidated balance sheets as of December 31, 2015. In addition, approximately \$0.2 million of pipeline assets were classified as held for sale as of December 31, 2015. As a result of this sale, the Company recognized a gain of approximately \$1.1 million.

During the year ended December 31, 2016, the Company sold additional pipeline assets, which resulted in proceeds of approximately \$0.4 million and a loss of less than \$0.1 million.

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During the year ended December 31, 2016, the Company received \$3.9 million from the sale of mineral interests related primarily to unproved properties to a third party. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and gas properties.

During the year ended December 31, 2016, the Company received \$4.8 million from the sale of unproved leases to a third party. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and gas properties.

During the year ended December 31, 2016, the Company received approximately \$63.8 million from a completed asset sale with a third party totaling approximately 9,900 acres. As a result of this sale, the Company recognized a loss of approximately \$7.6 million.

During the year ended December 31, 2017, the Company received approximately \$0.5 million from a completed asset sale with a third party totaling approximately 100 acres. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and natural gas properties.

During the year ended December 31, 2017, the Company received approximately \$0.8 million from a completed asset sale with a third party totaling approximately 150 acres. As a result of this sale, the Company recognized a gain of approximately \$0.2 million.

Acreage Trades

During the year ended December 31, 2015, the Company completed acreage trades with various working interest owners totaling approximately 10,500 acres. The exchanges were accounted for at net book value, with no gain or loss recognized. One of the trades involved the exchange of approximately 7,000 acres and the Company received a credit of \$17.5 million related to reimbursement of capital expenditures, which was recorded as a reduction of oil and natural gas properties. No other trades involved more than 1,500 acres and no significant cash was paid or received related to these other trades.

During the year ended December 31, 2016, the Company received approximately \$1.6 million from completed acreage trades with various working interest owners totaling approximately 249.5 acres. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and gas properties.

Note 5—Derivative Instruments

Commodity derivatives

The Company is exposed to market risk from changes in energy commodity prices within its operations. The Company utilizes derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas and oil. The Company currently uses a mix of over-the-counter fixed price swaps, basis swaps and put options spreads and collars to manage its exposure to commodity price fluctuations. All of the Company's derivative instruments are used for risk management purposes and none are held for trading or speculative purposes.

The Company is exposed to credit risk in the event of non-performance by counterparties. To mitigate this risk, the Company enters into derivative contracts only with counterparties that are rated "A" or higher by S&P or Moody's. The

creditworthiness of counterparties is subject to periodic review. As of December 31, 2017, the Company's derivative instruments were with Bank of Montreal, Citibank, KeyBank, N.A, Morgan Stanley, Capital One N.A., BP Energy Company and Goldman Sachs. The Company has not experienced any issues of non-performance by derivative counterparties. Below is a summary of the Company's derivative instrument positions, as of December 31, 2017, for future production periods:

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Natural Gas Derivatives

Description	Volume		Weighted Average
	(MMBtu/d)	Production Period	Price (\$/MMBtu)
Natural Gas Swaps:			
	30,000	January 2018 – March 2018	\$ 3.46
Natural Gas Three-way Collars:			
Floor purchase price (put)	30,000	January 2018 – March 2019	\$ 3.00
Ceiling sold price (call)	30,000	January 2018 – March 2019	\$ 3.40
Floor sold price (put)	30,000	January 2018 – March 2019	\$ 2.50
Floor purchase price (put)	40,000	January 2018 – March 2018	\$ 2.90
Floor purchase price (put)	40,000	April 2018 – December 2018	\$ 3.11
Ceiling sold price (call)	40,000	January 2018 – December 2018	\$ 3.38
Floor sold price (put)	40,000	January 2018 – December 2018	\$ 2.50
Floor purchase price (put)	60,000	January 2018 – March 2018	\$ 2.90
Ceiling sold price (call)	60,000	January 2018 – March 2018	\$ 3.75
Floor sold price (put)	60,000	January 2018 – March 2018	\$ 2.50
Floor purchase price (put)	60,000	January 2018 – December 2018	\$ 2.80
Ceiling sold price (call)	60,000	January 2018 – December 2018	\$ 3.35
Floor sold price (put)	60,000	January 2018 – December 2018	\$ 2.50
Natural Gas Call/Put Options:			
Call sold	40,000	January 2018 – December 2018	\$ 3.75
Call sold	10,000	January 2019 – December 2019	\$ 4.75
Basis Swaps:			
Appalachia - Dominion	60,000	January 2018 – March 2018	\$ (0.44)
Appalachia - Dominion	12,500	April 2019 – October 2019	\$ (0.52)
Appalachia - Dominion	12,500	April 2020 – October 2020	\$ (0.52)

Oil Derivatives

Description	Volume		Weighted Average
	(Bbls/d)	Production Period	Price (\$/Bbl)
Oil Three-way Collars:			
Floor purchase price (put)	4,000	January 2018 – December 2018	\$ 45.00
Ceiling sold price (call)	4,000	January 2018 – December 2018	\$ 52.25
Floor sold price (put)	4,000	January 2018 – December 2018	\$ 35.00

Fair values and gains (losses)

The following table summarizes the fair value of the Company's derivative instruments on a gross basis and on a net basis as presented in the consolidated balance sheets (in thousands). None of the derivative instruments are designated as hedges for accounting purposes.

			Net Amount	
		Netting	Presented in	
As of December 31, 2017	Gross Amount	Adjustments(a)	Balance Sheets	Balance Sheet Location
Assets				
Commodity derivatives - current	\$ 15,971	\$ (6,380)	\$ 9,591	Other current assets
Commodity derivatives - noncurrent	469	(176)	293	Other assets
Total assets	\$ 16,440	\$ (6,556)	\$ 9,884	
Liabilities				
Commodity derivatives - current	\$(21,256)	\$ 6,380	\$(14,876)	Accrued liabilities
Commodity derivatives - noncurrent	(252)	176	(76)	Other liabilities
Total liabilities	\$(21,508)	\$ 6,556	\$(14,952)	

				Net Amount	
					Presented in
	Gross	Netting		Balance	Balance Sheet
As of December 31, 2016	Amount	Adjustments(a)		Sheets	Location
Assets					
Commodity derivatives - current	\$ 50	\$ (50)	\$ —	
Commodity derivatives - noncurrent	—	—		—	
Total assets	\$ 50	\$ (50)	\$ —	
Liabilities					
					Accrued
Commodity derivatives - current	\$(35,459)	\$ 50		\$(35,409)	liabilities
					Other
Commodity derivatives - noncurrent	(12,673)	—		(12,673)	liabilities
Total liabilities	\$(48,132)	\$ 50		\$(48,082)	

(a) The Company has agreements in place that allow for the financial right to offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

The following table presents the Company's reported gains and losses on derivative instruments and where such values are recorded in the consolidated statements of operations for the periods presented (in thousands):

Location of Gain (Loss)		Years Ended December 31,		
		2017	2016	2015
Commodity derivatives	Gain (loss) on derivative instruments	\$45,365	\$(52,338)	\$56,021

Note 6—Fair Value Measurements

Fair Value Measurement on a Recurring Basis

The following table presents, by level within the fair value hierarchy, the Company's assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

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The fair value of the Company's derivatives is based on third-party pricing models, which utilize inputs that are readily available in the public market, such as natural gas forward curves. These values are compared to the values given by counterparties for reasonableness. Since natural gas swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2.

	Level 1	Level 2	Level 3	Total Fair Value
As of December 31, 2017: (in thousands)				
Commodity derivative instruments	\$ —	\$(5,068)	\$ —	\$ (5,068)
Total	\$ —	\$(5,068)	\$ —	\$ (5,068)
As of December 31, 2016: (in thousands)				
Commodity derivative instruments	\$ —	\$(48,082)	\$ —	\$ (48,082)
Total	\$ —	\$(48,082)	\$ —	\$ (48,082)

Nonfinancial Assets and Liabilities

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and natural gas property acquired include the Company's estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. Additionally, fair value is used to determine the inception value of the Company's AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company's ARO represent a nonrecurring Level 3 measurement. (See Note 2(n)).

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement. (See Note 2(l)).

The estimated fair values of the Company's financial instruments closely approximate the carrying amounts due, except for long-term debt. (See "Note 7— Debt")

Note 7—Debt

12.0% Senior Unsecured PIK Notes Due 2018

On June 26, 2013, the Company completed a private placement offering of an initial aggregate principal amount of \$300 million, with an additional \$100 million notes option, at the discretion of the Company, of 12% Senior Unsecured PIK notes due in 2018 (the "12.0% Senior PIK notes"). The 12.0% Senior PIK notes were issued at 96% of

par and the Company received \$280.7 million of net cash proceeds, after deducting the discount to initial purchasers of \$12 million and offering expenses of \$7.3 million. In December 2013, the Company exercised its option and issued an additional \$100 million of 12.0% Senior PIK notes with the same terms, at par. The Company received \$100 million net cash proceeds, as no discounts and \$0.2 million of offering expenses were incurred in connection with the exercise of the option.

The Company redeemed all of the outstanding balance of the 12.0% Senior PIK notes on July 13, 2015 for approximately \$510.7 million, including outstanding principal balance of \$437.3 million, a make-whole premium of \$47.6 million, and accrued interest of \$25.8 million. The make-whole premium plus unamortized discount and deferred financing costs of \$11.8 million were charged to loss on early extinguishment of debt, totaling \$59.4 million. The amount paid for the make-whole premium has been included as a financing activity in the consolidated statement of cash flows.

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Prior to the redemption of these notes, the Company amortized \$1.9 million of deferred financing costs and debt discount to interest expense using the effective interest method for the year ended December 31, 2015.

8.875% Senior Unsecured Notes Due 2023

On July 6, 2015, the Company issued \$550 million in aggregate principal amount of 8.875% Senior Unsecured Notes due 2023 at an issue price of 97.903% of principal amount of the notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the senior unsecured notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside of the United States in compliance with Rule S under the Securities Act. Upon closing, the Company received proceeds of approximately \$525.5 million, after deducting original issue discount, the initial purchasers discounts and offering expenses, of which the Company used approximately \$510.7 million to finance the redemption of all of its outstanding 12.0% Senior PIK notes. The Company used the remaining proceeds to fund its capital expenditure plan and for general corporate purposes.

During the years ended December 31, 2017, 2016, and 2015, the Company amortized \$3.4 million, \$3.3 million and \$1.5 million, respectively, of deferred financing costs and debt discount to interest expense using the effective interest method.

The indenture governing the senior unsecured notes contains covenants that, among other things, limit the ability of the Company and its restricted subsidiaries to: (i) incur additional indebtedness, (ii) pay dividends on capital stock or redeem, repurchase or retire the Company's capital stock or subordinated indebtedness, (iii) transfer or sell assets, (iv) make investments, (v) create certain liens, (vi) enter into agreements that restrict dividends or other payments to the Company from its restricted subsidiaries, (vii) consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries, taken as a whole, (viii) engage in transactions with affiliates, and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the indenture. In addition, if the senior unsecured notes achieve an investment grade rating from either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services, and no default under the indenture has then occurred and is continuing, many of such covenants will be suspended. The indenture also contains events of default, which include, among others and subject in certain cases to grace and cure periods, nonpayment of principal or interest, failure by the Company to comply with its other obligations under the indenture, payment defaults and accelerations with respect to certain other indebtedness of the Company and its restricted subsidiaries, failure of any guarantee on the senior unsecured notes to be enforceable, and certain events of bankruptcy or insolvency. The Company was in compliance with all applicable covenants in the indenture at December 31, 2017.

During the year ended December 31, 2016, the Company repurchased \$39.5 million of the outstanding senior unsecured notes in open market purchases for \$23.4 million. The principal of the outstanding senior unsecured notes that were repurchased less cash proceeds and unamortized debt discount and deferred financing costs were charged to gain on early extinguishment of debt, totaling \$14.5 million for the year ended December 31, 2016. The Company repurchased all such senior unsecured notes with cash on hand.

Based on Level 2 market data inputs, the fair value of the senior unsecured notes at December 31, 2017 was approximately \$524.1 million.

Revolving Credit Facility

During the first quarter of 2014, the Company entered into a \$500 million senior secured revolving bank credit facility (the "revolving credit facility") that was scheduled to mature in 2018. Borrowings under the revolving credit facility are subject to borrowing base limitations based on the collateral value of the Company's proved properties and commodity

hedge positions and are subject to semiannual redeterminations (April and October).

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The revolving credit facility was amended and restated on January 12, 2015. The primary change effected by the Amendment was to add Eclipse Resources Corporation as a party to the revolving credit facility and thereby subject the Company to the representations, warranties, covenants and events of default provisions thereof. Relative to the Eclipse I's previous credit agreement, the Credit Agreement also (i) requires financial reporting regarding, and tests financial covenants with respect to, Eclipse Resources Corporation rather than Eclipse I, (ii) increases the basket sizes under certain of the negative covenants, and (iii) includes certain other changes favorable to Eclipse I. Other terms of the Credit Agreement remain generally consistent with Eclipse I's previous credit agreement.

On February 24, 2016, the Company amended its revolving credit facility to, among other things, adjust the quarterly minimum interest coverage ratio, which is the ratio of EBITDAX to Cash Interest Expense, and to permit the sale of certain conventional properties. The amendment to the revolving credit facility also increased the Applicable Margin (as defined in the Credit Agreement) applicable to loans and letter of credit participation fees under the Credit Agreement by 0.5% and required the Company to, within 60 days of the effectiveness of the amendment, execute and deliver additional mortgages on the oil and gas properties that include at least 90% of the proved reserves.

On February 24, 2017, the Company entered into an additional amendment that increased the borrowing base from \$125 million to \$175 million, while extending the maturity of the revolving credit facility to February 2020. In addition, the amendment modified the minimum interest coverage ratio covenant to a net leverage covenant of Net Debt to EBITDAX. On August 1, 2017, the Company entered into an additional amendment that increased the borrowing base from \$175 million to \$225 million.

At December 31, 2017, the borrowing base was \$225 million and the Company had no outstanding borrowings. After giving effect to outstanding letters of credit issued by the Company totaling \$33.6 million, the Company had available borrowing capacity under the revolving credit facility of \$191.4 million. Subsequent to December 31, 2017, the Company borrowed \$45 million under its revolving credit facility, which reduced the available borrowing capacity to \$146.4 million. The Company's next scheduled borrowing base redetermination is expected to be completed by April 2018.

The revolving credit facility is secured by mortgages on substantially all of the Company's properties and guarantees from the Company's operating subsidiaries. The revolving credit facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and leverage coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company's election at the time of borrowing. The Company was in compliance with all applicable covenants under the revolving credit facility as of December 31, 2017. Commitment fees on the unused portion of the revolving credit facility are due quarterly at 0.5% of the unused facility based on utilization.

Note 8—Benefit Plans

Defined Contribution Plan

The Company currently maintains a retirement plan intended to provide benefits under section 401(K) of the Internal Revenue Code, under which employees are allowed to contribute portions of their compensation to a tax-qualified retirement account. Under the 401(K) plan, the Company provides matching contributions equal to 100% of the first 6% of employees' eligible compensation contributed to the plan. The Company recorded compensation expense of \$0.7 million, \$0.7 million and \$0.9 million related to matching contributions, classified under general and

administrative in the consolidated statements of operations, for the years ended December 31, 2017, 2016, and 2015, respectively.

Defined Benefit Plan

The Company maintained a defined benefit pension plan until October 2015. The plan covered 28 employees, of which two were retired, four had deferred vested termination, and one was a survivor. Benefits were based on the employees' years of service and compensation. As a result of the Oxford Acquisition on June 26, 2013, the Company assumed the defined benefit pension plan, and therefore, no pension benefit plan was in effect prior to such date. Effective March 31, 2014, benefit accruals in the plan were frozen resulting in a gain on reduction of

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pension liability of \$2.2 million for the year ended December 31, 2014. The plan was terminated during October 2015 and lump sum payments were made to the remaining participants.

The authoritative guidance for defined benefit pension plans requires an employer to recognize the overfunded or underfunded status as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

A summary of the pension benefit obligation as of the year ended December 31, 2015 is set forth in the below tables (in thousands):

	2015
Change in benefit obligation	
Benefit obligation at beginning of year	\$6,800
Service cost	—
Interest cost	239
Gain on reduction of pension liability	—
Actuarial (gain) loss	(775)
Benefits paid	(6,264)
Benefit obligation at end of period	\$—
Change in plan assets	
Fair value of plan assets at beginning of year	\$5,479
Actual return on plan assets	14
Employer contributions	771
Benefit paid	(6,264)
Fair value of plan assets at end of period	\$—

The funding level of the qualified pension plan was in compliance with standards set by applicable law or regulation. The plan was terminated during October 2015.

	2015
Beginning amount recorded in other accumulated	
comprehensive income (loss)	\$(548)
Amounts recorded in accumulated other	
comprehensive income (loss) consist of:	
Pension obligation adjustment, net of tax	548
Total recorded in accumulated other comprehensive	
income	\$—

The long-term expected rate of return on funded assets shown below was established for the benefit plan by developing a forward-looking, long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return was then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. The discount rate was determined by constructing a portfolio of high quality, noncallable bonds with cash flows that match estimated outflows for benefit payments.

	For the Year Ended
	December 31, 2015
Components of net periodic benefit cost	
(in thousands)	
Service cost	\$ —
Interest cost	239
Expected return on plan assets	(246)
Amortization of transition obligation	—
Amortization of net (gain) loss	42
Effect of settlement	224
Net period benefit cost	\$ 259

Note 9—Stock-Based Compensation

The Company is authorized to grant up to 25,000,000 shares of common stock under its 2014 Long-Term Incentive Plan (as amended, the “Plan”). The Plan allows stock-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent rights, qualified performance-based awards and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of the Company’s Board of Directors. A total of 10,924,403 shares are available for future grant under the Plan as of December 31, 2017.

Our stock based compensation expense is as follows for the years ended December 31, 2017, 2016, and 2015 (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Restricted stock units	\$5,301	\$4,006	\$2,408
Performance units	3,622	1,922	1,297
Restricted stock issued to directors	378	556	827
Incentive units	—	(268)	103
Total expense	\$9,301	\$6,216	\$4,635

Restricted Stock Units

Restricted stock unit awards vest subject to the satisfaction of service requirements. The Company recognizes expense related to restricted stock and restricted stock unit awards on a straight-line basis over the requisite service period, which is three years. The grant date fair values of these awards are determined based on the closing price of the Company's common stock on the date of the grant. As of December 31, 2017, there was \$5.9 million of total unrecognized compensation cost related to restricted stock units. The weighted average period for the shares to vest is approximately 1 year.

A summary of restricted stock unit awards activity during the year ended December 31, 2017 is as follows:

	Number of	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested, December 31, 2016	4,343,582	\$ 2.14	\$ 11,597
Granted	2,692,797	2.12	
Vested	(2,914,881)	1.65	
Forfeited	(64,144)	2.46	
Total awarded and unvested, December 31, 2017	4,057,354	\$ 2.48	\$ 9,738

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Performance Units

Performance unit awards vest subject to the satisfaction of a three-year service requirement and based on Total Shareholder Return (“TSR”), as compared to an industry peer group over that same period. The performance unit awards are measured at the grant date at fair value using a Monte Carlo valuation method. As of December 31, 2017, there was \$5.0 million of total unrecognized compensation cost related to performance units. The weighted average period for the shares to vest is approximately 2 years.

A summary of performance stock unit awards activity during the year ended December 31, 2017 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested, December 31, 2016	1,928,002	\$ 3.31	\$ 5,148
Granted	2,564,523	1.94	
Vested	(448,018)	8.77	
Forfeited	(78,130)	2.75	
Total awarded and unvested, December 31, 2017	3,966,377	\$ 1.82	\$ 11,257

The determination of the fair value of the performance unit awards noted above uses significant Level 3 assumptions in the fair value hierarchy including an estimate of the timing of forfeitures, the risk free rate and a volatility estimate tied to the Company’s public peer group. The following table presents the assumptions used to determine the fair value for performance stock units granted during the years ended December 31, 2017, 2016, and 2015:

	Year Ended December 31,		
	2017	2016	2015
Volatility	50.41 %	49.84 %	44.25 %
Risk-free interest rate	1.34 %	0.96 %	0.94 %

The fair value of the performance stock units vested during the year ended December 31, 2017 was approximately \$0.8 million.

Restricted Stock Issued to Directors

On October 7, 2014, the Company issued an aggregate of 31,115 restricted shares of common stock to its seven non-employee members of its Board of Directors, which became fully vested on June 25, 2015. For the year ended

December 31, 2015, the Company recognized expense of approximately \$0.3 million related to these awards.

On May 11, 2015, the Company issued an aggregate of 132,496 restricted shares of common stock to its seven non-employee members of its Board of Directors, which became fully vested on May 11, 2016. For the years ended December 31, 2016 and 2015, the Company recognized expense of approximately \$0.3 million and \$0.6 million, respectively, related to these awards.

On May 18, 2016, the Company issued an aggregate of 149,448 restricted shares of common stock to its three non-employee members of its Board of Directors that are not affiliated with the Company's controlling stockholder, which became fully vested on May 18, 2017. For the years ended December 31, 2017 and 2016, the Company recognized expense of approximately \$0.2 million and \$0.3 million, respectively, related to these awards.

On May 17, 2017, the Company issued an aggregate of 153,192 restricted shares of common stock to its three non-employee members of its Board of Directors that are not affiliated with the Company's controlling stockholder, which are scheduled to fully vest on May 17, 2018. For the year ended December 31, 2017, the Company recognized expense of approximately \$0.2 million related to these awards. As of December 31, 2017, there was

approximately \$0.1 million of total unrecognized compensation cost related to outstanding restricted stock issued to the Company's Directors.

Note 10—Equity

Private Placement of Common Stock

On December 27, 2014, the Company entered into a Securities Purchase Agreement with private equity funds managed by EnCap Investments L.P., entities controlled by certain members of the Company's management team and certain other institutional investors pursuant to which the Company issued and sold to such purchasers an aggregate of 62,500,000 shares of common stock at a price of \$7.04 per share pursuant to the exemptions from registration provided in Rule 506 of Regulation D promulgated under Section 4(2) of the Securities Act (the "Private Placement").

On January 28, 2015, the Company closed the Private Placement and received net proceeds of approximately \$434 million (after deducting placement agent commissions and estimated expenses), which the Company intends to use to fund its capital expenditure plan and for general corporate purposes. Upon the closing of the Private Placement, the Company amended and restated the existing registration rights agreement that was entered into upon the closing of its IPO in order to provide the purchasers with certain registration rights with respect to the stock they purchased in the Private Placement. The Company completed the registration of the shares during the third quarter of 2015.

Public Offering of Common Stock

On June 28, 2016, the Company commenced an underwritten public offering of 37,500,000 shares of common stock, which was priced at \$3.50 per share. The Company closed the offering on July 5, 2016 and received net proceeds of approximately \$123.8 million (after deducting underwriting discounts and commissions and estimated expenses), which the Company used to fund its capital expenditure plan and for general corporate purposes.

Note 11—Earnings (Loss) Per Share

Earnings (Loss) Per Share

Basic earnings (loss) per share ("EPS") is computed by dividing net income (loss) by the weighted-average number of shares of common stock outstanding during the period. Diluted EPS takes into account the dilutive effect of potential common stock that could be issued by the Company in conjunction with any stock awards that have been granted to directors and employees. In accordance with FASB ASC Topic 260, awards of non-vested shares shall be considered to be outstanding as of the grant date for purposes of computing diluted EPS even though their exercise is contingent upon vesting. During periods in which the Company incurs a net loss, diluted weighted-average shares outstanding are equal to basic weighted-average shares outstanding because the effect of all equity awards is antidilutive. The following is a calculation of the basic and diluted weighted-average number of shares of common stock outstanding and EPS for the years ended December 31, 2017, 2016, and 2015, respectively:

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(in thousands, except per share data)	Year Ended December 31,								
	2017			2016			2015		
	Income		Per	Income		Per	Income		Per
	(Loss)	Shares	Share	(Loss)	Shares	Share	(Loss)	Shares	Share
Basic:									
Net income (loss), shares,									
basic	\$8,525	262,181	\$0.03	\$(206,735)	241,434	\$(0.86)	\$(961,791)	217,897	\$(4.41)
Weighted-average number of									
shares of common									
stock-diluted:									
Restricted stock and									
performance unit awards	—	3,001		—	—		—	—	
Diluted:									
Net income (loss), shares,									
diluted	\$8,525	265,182	\$0.03	\$(206,735)	241,434	\$(0.86)	\$(961,791)	217,897	\$(4.41)

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Note 12—Related Party Transactions

As of December 31, 2014, the Company had recorded an accrued liability of approximately \$1.0 million related to an estimated final distribution of the assets of Eclipse Resources Operating, LLC (“Eclipse Operating”), which is the Company’s predecessor management company that the Company acquired as part of the reorganization completed at the time of the Company’s IPO. The actual distribution of approximately \$0.6 million was distributed equally among the three former shareholders during 2015 and the remaining \$0.4 million reflected as a reduction of initial gain recorded on the acquisition of Eclipse Operating, which is classified within “Other income” in the consolidated statements of operations.

During the years ended December 31, 2017, 2016, and 2015, the Company incurred approximately \$0.6 million, \$0.6 million and \$0.3 million, respectively, related to flight charter services provided by BWH Air, LLC and BWH Air II, LLC, which are owned by the Company’s Chairman, President and Chief Executive Officer. The fees are paid in accordance with a standard service contract that does not obligate the Company to any minimum terms.

Note 13—Commitments and Contingencies

(a) Legal Matters

From time to time, the Company may be a party to legal proceedings arising in the ordinary course of business. Management does not believe that a material loss is probable as a result of such proceedings.

(b) Environmental Matters

The Company is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of the Company could be adversely affected.

(c) Leases

The development of the Company’s oil and natural gas properties under their related leases will require a significant amount of capital. The timing of those expenditures will be determined by the lease provisions, the term of the lease and other factors associated with unproved leasehold acreage. To the extent that the Company is not the operator of oil and natural gas properties that it owns an interest in, the timing, and to some degree the amount, of capital expenditures will be controlled by the operator of such properties.

The Company leases office space under an operating lease that expires in 2024. Rent expense related to lease agreements for the years ended December 31, 2017, 2016, and 2015 was \$0.6 million, \$0.9 million and \$1.1 million,

respectively.

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The following is a schedule by year, of the future minimum lease payments required under the lease agreements as of December 31, 2017 (in thousands).

2018	637
2019	635
2020	689
2021	684
2022	684
Thereafter	1,368
Total minimum lease payments	\$4,697

(d) Other Commitments (in thousands)

	Drilling rig commitments ⁽ⁱ⁾	Firm transportation ⁽ⁱⁱ⁾	Gas processing, gathering, and compression services ⁽ⁱⁱⁱ⁾	Total
Year Ending December 31:				
2018	\$ 11,678	\$ 84,167	\$ 14,186	\$110,031
2019	—	109,716	15,407	125,123
2020	—	109,976	6,999	116,975
2021	—	105,773	—	105,773
2022	—	102,476	—	102,476
Thereafter	—	885,139	—	885,139
Total	\$ 11,678	\$ 1,397,247	\$ 36,592	\$1,445,517

(i) Drilling rig commitments -The Company had contracts for the service of two rigs, which one expires in September 2018 and one expires in October 2018 both with the option to extend. The values in the table represent the gross amounts that the Company is committed to pay and does not deduct amounts that other parties are responsible for as a result of cost sharing arrangements with working interest partners. The Company will record in its consolidated financial statements the Company's proportionate share of costs based on its working interest, as applicable.

(ii) Firm transportation -The Company has entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit the Company to transport minimum daily natural gas or NGL volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent the minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that the Company is committed to pay and does not deduct amounts that other parties are responsible for as a result of cost sharing arrangements with working interest partners. The Company will record in its consolidated financial statements the Company's proportionate share of costs based on its working interest.

(iii) Gas processing, gathering, and compression services -Contractual commitments for gas processing, gathering and compression service agreements represent minimum commitments under long-term gas processing agreements as

well as various gas compression agreements. The values in the table represent the gross amounts that the Company is committed to pay and does not deduct amounts that other parties are responsible for as a result of cost sharing arrangements with working interest partners. The Company will record in its consolidated financial statements its proportionate share of costs based on the Company's working interest. Further, the values in the table do not include any commitments based on our amended agreement with Eureka Midstream contracted subsequent to year-end.

Note 14—Income Tax

For the year ended December 31, 2017, the Company's annual effective tax rate is approximately 0.0%. The Company incurred a tax loss in the current year (due principally to intangible drilling cost amortization) and thus, no current federal income taxes will be due. This tax loss results in a net operating loss carryforward at December 31, 2017. Management assessed the realizability of the Company's deferred tax assets based on the more likely than not standard. Management considered several factors such as: (i) the Company's short tax history, (ii) the lack of carryback potential resulting in a tax refund, and (iii) in light of current commodity pricing uncertainty, there is insufficient external evidence to suggest that net federal tax attribute carryforwards are realizable. As such, the Company has provided a valuation allowance of \$214 million as of December 31, 2017.

	For the Year Ended December 31,		
	2017	2016	2015
Current			
Federal	\$—	\$—	\$—
State	—	6	315
Total current	—	6	315
Deferred			
Federal	—	—	(74,133)
State	—	540	(348)
Total deferred	—	540	(74,481)
Total income tax expense (benefit)	\$—	\$546	\$(74,166)

The Company's income tax expense differs from the amount derived by applying the statutory federal rate to pretax loss principally due the effect of the following items (in thousands):

	For the Year Ended December 31,					
	2017		2016		2015	
Income (loss) before income taxes	\$8,525		\$(206,189)		\$(1,035,957)	
Statutory rate	35	%	35	%	35	%
Income tax benefit computed at statutory rate	2,984		(72,166)		(362,585)	
Reconciling items:						
State income taxes	—		546		(21)	
Other, net	50		854		795	
Gain on acquisition of Eclipse Operating	—		—		(141)	
Share-based compensation	(576)		—		—	
Executive compensation limitation	496		—		—	
Change in valuation allowance	(145,449)		71,312		287,786	
Change in Federal tax rate	142,495		—		—	
Income tax expense (benefit)	\$—		\$546		\$(74,166)	

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below (in thousands):

	For the Year Ended December 31,		
	2017	2016	2015
Deferred tax asset:			
Oil and gas properties and equipment	\$93,854	\$193,095	\$235,884
Federal tax loss carryforwards	114,652	145,628	61,006
Derivative instruments and other	1,064	16,829	—
State effect of deferreds	—	—	540
Other, net	4,639	4,259	3,434
Deferred tax asset	214,209	359,811	300,864
Valuation allowance	(213,800)	(359,098)	(287,786)
Net deferred tax assets	\$409	\$713	\$13,078
Deferred tax liability:			
Derivative instruments and other	\$—	\$—	\$12,054
Other, net	409	713	484
Net deferred tax liability	\$409	\$713	\$12,538
Reflected in the accompanying consolidated balance sheet as:			
Net deferred tax asset	\$—	\$—	\$540
Net deferred tax liability	\$—	\$—	\$—

The Company has U.S. federal tax loss carryforwards (“NOL”) of approximately \$546 million as of December 31, 2017. The NOL carryforwards will begin to expire in 2034. The tax years ended December 31, 2016, 2015 and 2014 will remain open to examination under the applicable statute of limitations in the U.S. and other jurisdictions in which the Company and its subsidiaries file income tax returns. However, the statute of limitations for examination of NOLs and other similar attribute carryforwards does not commence until the year the attribute is utilized. In some instances, state statutes of limitations are longer than those under U.S. federal tax law.

The change in the Federal tax rate was due to the passage of Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the “Act”). Due to the reduction in the U.S. statutory tax rate from 35% to 21%, the Company recorded a \$142 million reduction of tax benefit and a corresponding \$142 million reversal of valuation allowance previously recorded, as it is required to reflect the change in the period in which the law is enacted. The impact of the Tax Reform resulted in a net \$0 impact to the Company’s income tax provision. Based on the Company’s current interpretation of the Act and subject to the release of the related regulations and any future interpretive guidance, the Company believes the effects of the change in tax law incorporated herein are substantially complete.

As of December 31, 2017, 2016, and 2015 the Company has not recorded a reserve for any uncertain tax positions. No federal income tax payments are expected in the upcoming four quarterly reporting periods.

During the second quarter of 2017, the Internal Revenue Service completed its examination of Eclipse Resources Corporation for its tax year 2014. There were no adjustments to the Company’s tax returns as a result of the examination.

Note 15—Subsidiary Guarantors

The Company's wholly owned subsidiaries each have fully and unconditionally, joint and severally, guaranteed the Company's 8.875% Senior Unsecured Notes (See Note 7— Debt). The Parent company has no independent assets or operations. The Company's wholly owned subsidiaries are not restricted from transferring

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funds to the Parent or other wholly owned subsidiaries. The Company's wholly owned subsidiaries do not have any restricted net assets.

A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person by way of merger, consolidation, or otherwise; or
- if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

Note 16—Subsequent Events

Management has evaluated subsequent events and believes that there are no events that would have a material impact on the aforementioned financial statements and related disclosures, except for the Flat Castle Acquisition in January 2018 and a draw on our revolving credit facility (See Note 3 — Acquisition and Note 7 — Debt).

Note 17—Quarterly Financial Information (unaudited)

Summarized quarterly financial data for the years ended December 31, 2017 and 2016 are presented in the following table. In the following table, the sum of basic and diluted "Loss per common share" for the four quarters may differ from the annual amounts due to the required method of computing weighted average number of shares in the respective periods. Additionally, due to the effect of rounding, the sum of the individual quarterly loss per share amounts may not equal the calculated year loss per share amount (in thousands, except per share data).

	First	Second	Third	Fourth
	Quarter	Quarter	Quarter	Quarter
Year ended December 31, 2017				
Total operating revenues	\$ 101,863	\$ 86,191	\$ 91,549	\$ 104,056
Total operating expenses	87,632	80,589	94,338	108,431
Operating income (loss)	14,231	5,602	(2,789)	(4,375)
Net income (loss)	26,847	11,494	(16,694)	(13,122)
Income (loss) per common share:				
Basic	\$ 0.10	\$ 0.04	\$ (0.06)	\$ (0.05)
Diluted	\$ 0.10	\$ 0.04	\$ (0.06)	\$ (0.05)
	First	Second	Third	Fourth

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	Quarter	Quarter	Quarter	Quarter
Year ended December 31, 2016				
Total operating revenues	\$49,606	\$47,066	\$54,479	\$83,883
Total operating expenses	100,214	84,017	78,678	89,527
Operating loss	(50,608)	(36,951)	(24,199)	(5,644)
Net loss	(45,534)	(73,163)	(25,949)	(62,089)
Loss per common share:				
Basic and diluted	\$(0.20)	\$(0.33)	\$(0.10)	\$(0.23)

Note 18—Supplemental Oil and Natural Gas Information (unaudited)

(a) Capitalized Costs

A summary of the Company's capitalized costs are contained in the table below (in thousands):

	December 31,	
	2017	2016
Oil and natural gas properties:		
Unproved properties	\$459,549	\$526,270
Proved properties	1,896,081	1,545,860
Total oil and natural gas properties	2,355,630	2,072,130
Less accumulated depreciation, depletion and amortization	(1,248,200)	(1,131,378)
Net oil and natural gas properties	\$1,107,430	\$940,752

(b) Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities

A summary of the Company's cost incurred in oil and natural gas property acquisition and development activities is set forth below (in thousands):

	December 31,		
	2017	2016	2015
Acquisition costs:			
Unproved properties	\$57,498	\$24,764	\$24,722
Proved properties	—	—	—
Development cost	257,119	150,778	259,655
Exploration cost	18,791	20,127	20,530
Total acquisition, development and exploration costs	\$333,408	\$195,669	\$304,907

(c) Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2017 and December 31, 2016, which have been prepared and presented under SEC rules. These rules require companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company's reserves as of December 31, 2017, 2016, and 2015 was based on an unweighted average 12-month average West Texas Intermediate posted price per Bbl for oil and NGLs and a Henry Hub spot natural gas price per MMBtu for natural gas.

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement may limit the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Appalachian Basin of Ohio. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are all located in the United States, within the State of Ohio. All of the estimates of the proved reserves at December 31, 2017, 2016, and 2015, were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

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Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates.

Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a roll-forward of the total proved reserves for the year ended December 31, 2017, 2016, and 2015 as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

	Natural Gas	Natural Gas		
	Natural Gas	Liquids	Oil	TOTAL
	(Bcf)	(MBbl)	(MBbl)	(Bcfe)
End of year, December 31, 2014	256.3	10,879.0	5,697.4	355.8
Revisions	(115.3)	(4,705.7)	(1,550.1)	(152.9)
Extensions and discoveries	182.6	4,035.7	2,496.3	221.7
Production	(49.5)	(2,450.3)	(1,950.5)	(75.8)
End of year, December 31, 2015	274.1	7,758.7	4,693.1	348.8
Revisions	(0.1)	1,273.7	1,196.8	14.8
Extensions and discoveries	175.4	2,156.0	1,300.2	196.1
Acquisitions	3.8	24.8	15.1	4.1
Divestitures	(5.9)	(91.5)	(703.7)	(10.7)
Production	(60.9)	(2,446.2)	(1,343.8)	(83.7)
End of year, December 31, 2016	386.4	8,675.5	5,157.7	469.4
Revisions	515.1	20,327.3	9,746.8	695.6
Extensions and discoveries	274.4	15,598.8	6,192.9	405.1
Acquisitions	1.6	42.6	5.8	1.9
Production	(87.4)	(2,713.6)	(1,622.4)	(113.4)
End of year, December 31, 2017	1,090.1	41,930.6	19,480.8	1,458.6
Proved developed reserves:				
December 31, 2015	209.5	7,245.7	4,239.2	278.4
December 31, 2016	226.1	7,520.0	4,439.5	297.8
December 31, 2017	334.6	13,782.9	6,449.6	456.0
Proved undeveloped reserves:				
December 31, 2015	64.5	513.0	453.9	70.3
December 31, 2016	160.4	1,155.5	718.1	171.6
December 31, 2017	755.5	28,147.7	13,031.2	1,002.6

Extensions and discoveries of 405.1 Bcfe and 196.1 Bcfe during the years ended December 31, 2017 and December 31, 2016, respectively, resulted primarily from the drilling of new wells during each year and from new proved undeveloped locations. The revisions consisted of positive revisions of 27.0 Bcfe due to technical adjustments and 668.6 Bcfe due to pricing and differential changes.

(d) Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties, and consideration of expected future economic and operating conditions. The estimates of

future cash flows and future production and development costs as of December 31, 2017 and 2016 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%. The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows at December 31, 2017, 2016, and 2015 (in thousands):

	December 31,		
	2017	2016	2015
Future cash inflows (total revenues)	\$4,750,238	\$1,143,142	\$975,664
Future production costs	(2,332,310)	(725,724)	(592,073)
Future development costs (capital costs)	(879,399)	(116,988)	(83,532)
Future income tax expense	—	—	—
Future net cash flows	1,538,529	300,430	300,059
10% annual discount for estimated timing of			
cash flows	(808,843)	(94,449)	(87,194)
Standardized measure of Discounted Future Net			
Cash Flow	\$729,686	\$205,981	\$212,865

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

(e) Changes in the Standardized Measure of Discounted Future Net Cash Flows

A summary of the changes in the standardized measure of discounted future net cash flows are contained in the table below (in thousands):

	December 31,		
	2017	2016	2015
Standardized Measure, beginning of the year	\$205,981	\$212,865	\$330,657
Net change in prices and production costs	653,347	(33,507)	(372,664)
Net change in future development costs	(385,042)	1,552	79,244
Sales, less production costs	(226,324)	(99,768)	(121,646)
Extensions	135,734	79,941	107,749
Acquisitions	2,365	1,045	—
Divestitures	—	(5,231)	—
Revisions of previous quantity estimates	322,917	15,754	(97,210)
Previously estimated development costs incurred	34,102	4,886	62,906

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Accretion of discount	20,598	21,287	50,939
Net change in taxes	—	—	178,732
Changes in timing and other	(33,992)	7,157	(5,842)
Standardized Measure, end of year	\$729,686	\$205,981	\$212,865

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