SABINE OIL & GAS CORP
Form 10-K
March 24, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015
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: 01-13515

SABINE OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

New York	25-0484900

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

1415 Louisiana Street, Suite 1600
Houston, Texas 77002
(Address of principal executive offices, including zip code)

Registrant’s telephone number, including area code: (832) 242-9600

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

Title of class	Name of each exchange on which registered
Common Stock, Par Value $0.10 Per Share	OTC Pink Marketplace

Securities registered pursuant to Section 12 (g) of the Act: None

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2015 was approximately $14 million, based upon the closing price of $0.07 per share as reported by the New York Stock Exchange on such date.

211,693,364 shares of our $0.10 par value common stock were outstanding on March 21, 2016.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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EXPLANATORY NOTE

As discussed in “Items 1 and 2. Business and Properties” below, on December 16, 2014, Sabine Oil & Gas LLC, a Delaware limited liability company (“Sabine O&G”), and Forest Oil Corporation, a New York corporation, completed the combination of their respective businesses through a series of transactions (“the Combination”) whereby certain indirect equity holders of Sabine O&G contributed the equity interests in Sabine O&G to Forest Oil Corporation. In exchange for this contribution, the equity holders of Sabine O&G received shares of Sabine Oil & Gas Corporation (“Sabine”) common stock and Series A senior non-voting equity-equivalent preferred stock collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine (the “Combination”). On December 19, 2014, Forest Oil Corporation changed its name to “Sabine Oil & Gas Corporation.” Because Sabine O&G was considered the accounting acquirer in the Combination under US GAAP, Sabine O&G is also considered the accounting predecessor of Sabine Oil & Gas Corporation. Accordingly, the historical financial and operating data of Sabine Oil & Gas Corporation included in this Annual Report on Form 10-K which cover periods prior to the completion of the Combination, reflect the assets, liabilities and operations of Sabine O&G, the predecessor to Sabine Oil & Gas Corporation, and do not reflect the assets, liabilities and operations of Sabine Oil & Gas Corporation (which was then known as “Forest Oil Corporation”) prior to the Combination. References in this Annual Report on Form 10-K to “Sabine,” “the Company,” “we,” “us” and “our” refer (i) with respect to the period from and after December 16, 2014, to the group of entities within the consolidated group of Sabine Oil & Gas Corporation, and (ii) with respect to the period prior to December 16, 2014, to the group of entities within the consolidated group of Sabine O&G, the predecessor, unless, in each case, otherwise indicated or the context otherwise requires. References in this Annual Report on Form 10-K to “Forest” refer to Sabine Oil & Gas Corporation prior to the Combination, when it was known as “Forest Oil Corporation.” For more information regarding Forest’s historical operating data, please see the Company’s prior Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q.

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Certain Terms Used in this Annual Report on Form 10-K

Unless the context otherwise requires, references in this Annual Report on Form 10-K to the following terms have the meanings set forth below:

- "Bankruptcy Code" refers to title 11 of the United States Code.
- "Bankruptcy Court" refers to the United States Bankruptcy Court for the Southern District of New York.
- "Bar Dates" means the deadlines for filing certain proofs of claims in the Debtors' Chapter 11 cases, which deadline is December 22, 2015 for general claims and January 11, 2016 for governmental claims.
- "Combination" refers to the consummation of a series of transactions whereby certain indirect equity holders of Sabine O&G contributed the equity interests in Sabine O&G to Sabine Oil & Gas Corporation (which was then known as "Forest Oil Corporation"). In exchange for this contribution, the equity holders of Sabine O&G received shares of Sabine common stock and Series A senior non-voting equity-equivalent preferred stock ("Sabine Series A preferred stock") collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine. The Combination was completed on December 16, 2014.
- "Chapter 11" refers to chapter 11 of the Bankruptcy Code which may also be referred to herein as "Chapter 11 Cases" or "Chapter 11 Proceedings".
- "Debtors" refers to the Company and certain of its subsidiaries, including Giant Gas Gathering LLC, Sabine Bear Paw Basin LLC, Sabine East Texas Basin LLC, Sabine Mid-Continent Gathering LLC, Sabine Mid-Continent LLC, Sabine Oil & Gas Finance Corp., Sabine South Texas Gathering LLC, Sabine South Texas LLC and Sabine Williston Basin LLC.
- "Forest" refers to Sabine Oil & Gas Corporation, a New York corporation, prior to the Combination, which was then known as "Forest Oil Corporation." Forest changed its name to "Sabine Oil & Gas Corporation" on December 19, 2014.
- "Sabine," "we," "us" or the "Company" refers (i) with respect to the period from and after December 16, 2014, the date of the Combination, to the group of entities within the consolidated group of Sabine Oil & Gas Corporation, a New York corporation and the entity which survived the Combination and (ii) with respect to the period prior to December 16, 2014, to the group of entities within the consolidated group of Sabine O&G.
- "Sabine Investor Holdings" refers to Sabine Investor Holdings LLC, a Delaware limited liability company, of which the common equity interests are owned by affiliates of First Reserve, certain members of the Company's management and board of directors.
- "Sabine O&G" refers to Sabine Oil & Gas LLC, a Delaware limited liability company and the accounting predecessor of Sabine.
- "Sabine O&G Properties" refer to the oil and natural gas properties historically owned by Sabine O&G prior to the Combination.
- "Sabine Oil & Gas Corporation" refers to Sabine Oil & Gas Corporation, a New York corporation.

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Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Annual Report on Form 10-K. Certain definitions, including the definitions of proved reserves, proved developed reserves, and proved undeveloped reserves, have been abbreviated from the applicable definitions contained in Rule 4-10 (a) of Regulation S-X under the Securities Exchange Act of 1934.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

Bbtu. One billion British Thermal Units.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

Btu. A British Thermal Unit, or the amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit.

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

Developed acreage. Acreage that is held by producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole; dry well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. Also referred to as a non-productive well.

Equivalent volumes. Equivalent volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

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

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location or the undertaking of other work obligations.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Full cost pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration, and development activities are included. Any costs related to production, general and administrative expense, or similar activities are not included.

Gas. Natural Gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

HH or Henry Hub. Henry Hub is the major exchange for pricing natural gas futures on the NYMEX.

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Hydraulic fracturing. A process used to stimulate production of hydrocarbons. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

Liquids. Oil, condensate, and natural gas liquids.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

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

MBoe. Thousand barrels of crude oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

MMBoe. One million barrels of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

MMbtu. One million British Thermal Units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids.

MMcfe/d. One million cubic feet of gas equivalent per day.

NGL or natural gas liquids. Liquid hydrocarbons found in natural gas which may be extracted as separate components, including ethane, propane, butanes, and natural gasoline.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers.

Net revenue interest. An owner's share of petroleum after satisfaction of all royalty and other non-cost bearing interests.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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

Productive wells. Producing wells and wells that are mechanically capable of production.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. Quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Existing economic conditions include prices and costs which economic productability from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the end of the reporting period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves or PUDs. Estimated 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.

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

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

Spot market price. The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

Tcfe. One trillion cubic feet of gas equivalent.

Standardized measure or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and property taxes, future capital costs, operating expenses, and estimated future income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC’s requirements, to determine their “present value.” The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the estimation date in accordance with the SEC’s regulations and are held constant for the life of the reserves.

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

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

Workover. A series of operations on a producing well to restore or increase production.

WTI or West Texas Intermediate. A grade of crude oil used as a benchmark in oil pricing.

3-D Seismic. Advanced technology method of detecting accumulations of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K and the documents referred to in this Annual Report on Form 10-K contain "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, 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"). Forward-looking statements are statements that are not statements of historical fact, including statements about beliefs, opinions and expectations. Forward-looking statements are based on, and include statements about, our plans, prospects, expected future financial condition, results of operations, cash flows, dividends and dividend plans, objectives, beliefs, financing plans, business strategies, budgets, goals, future events, future revenues or performance, financing needs, outcomes of litigation, projected costs, operating metrics, capital expenditures, competitive positions, acquisitions, investment opportunities, integration, cost savings, synergies, growth opportunities, dispositions, plans and objectives of management for future operations and any other information that is not historical information. These statements, which may include statements regarding the period following completion of the reincorporation merger and the related transactions, include, without limitation, words such as "may," "will," "could," "should," "would," "expect," "plan," "project," "forecast," " "anticipate," "believe," "estimate," "predict," "suggest," "view," "potential," "pursue," "target," "continue" and similar express variations as well as the negative of these terms. These statements involve risks, uncertainties, assumptions and other factors that are difficult to predict and that could cause actual results to differ materially from those expressed in them or indicated by them.

These risks and uncertainties are not exhaustive. Other sections of this Annual Report on Form 10-K describe additional factors that could adversely affect our business and financial performance. Moreover, we operate in a very competitive and rapidly changing environment. New risks and uncertainties emerge from time to time, and it is not possible to predict all risks and uncertainties, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

Although we believe the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, level of activity, performance or achievements. Moreover, neither we nor any other person assumes responsibility for the accuracy or completeness of any of these forward-looking statements. You should not rely upon forward-looking statements as predictions of future events. We are under no duty to update any of these forward-looking statements after the date of this Annual Report on Form 10-K to conform our prior statements to actual results or revised expectations and we do not intend to do so.

These forward-looking statements appear in a number of places and include statements with respect to, among other things:

- risks and uncertainties associated with the Chapter 11 process, including our inability to develop, confirm and consummate a plan under Chapter 11 of the Bankruptcy Code or an alternative restructuring transaction, including a sale of all or substantially all of our assets, which may be necessary to continue as a going concern;
- inability to maintain our relationship with suppliers, customers, employees and other third parties as a result of our Chapter 11 filing;
- failure to satisfy our short- or long-term liquidity needs, including our inability to generate sufficient cash flow from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs and our ability to continue as a going concern;
- estimates of our oil and natural gas reserves;
- our future financial condition, results of operations, revenues, cash flows, and expenses;
- our future levels of indebtedness, liquidity, and compliance with debt covenants;
- our ability to access the capital markets and the terms on which capital may be available to us;

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- our ability to fund our operations and capital expenditures;
- our future business strategy and other plans and objectives for future operations;
- our ability to integrate the historical Forest and Sabine O&G businesses and achieve synergies related to the Combination;
- our business' competitive position;
- our outlook on oil and natural gas prices;
- the amount, nature, and timing of our future capital expenditures, including future development costs;
- our potential future asset dispositions and other transactions, the timing of closing of such transactions and the use of proceeds, if any, from such transactions;
- the risks associated with potential acquisitions or alliances by us;
- the recruitment and retention of our officers and employees;
- our expected levels of compensation;
- the likelihood of success of and impact of litigation on us;
- our assessment of our counterparty risk and the ability of our counterparties to perform their future obligations; and
- the impact of federal, state, and local political, regulatory, and environmental developments in the United States where we conduct business operations.

We expressly qualify in its entirety each forward-looking statement attributable to us or any person acting on our behalf by the cautionary statements contained or referred to in this section. Except to the extent required by applicable law or regulation, we do not undertake any obligation to update forward-looking statements to reflect events or circumstances after the date of this Annual Report on Form 10-K or to reflect the occurrence of unanticipated events.

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PART I

You should read this entire report carefully, including the risks described under Part I, Item 1A. Risk Factors and our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this Annual Report on Form 10-K. For the reasons discussed in the Explanatory Note to this Annual Report on Form 10-K, references in this Annual Report on Form 10-K to “Sabine,” “the Company,” “we,” “us” and “our” refer (i) with respect to the period from and after December 16, 2014, to the group of entities within the consolidated group of Sabine Oil & Gas Corporation, and (ii) with respect to the period prior to December 16, 2014, to the group of entities within the consolidated group of Sabine O&G, the accounting predecessor, unless, in each case, otherwise indicated or the context otherwise requires. References in this Annual Report on Form 10-K to “Forest” refer to Sabine Oil & Gas Corporation prior to the Combination, when it was known as “Forest Oil Corporation.”

Items 1 and 2.Business and Properties

General

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties onshore in the United States.

On December 16, 2014, pursuant to a series of transaction agreements, certain indirect equity holders of Sabine O&G (such indirect equity holders are referred to as the “Legacy Sabine Investors”) contributed the equity interests in Sabine O&G to us (we were then known as “Forest Oil Corporation”). In exchange for this contribution, the Legacy Sabine Investors received shares of our common stock and our Series A preferred stock collectively representing approximately a 73.5% economic interest in us and 40% of the total voting power in us. Holders of our common stock immediately prior to the closing of the Combination continued to hold their common stock following the closing, which immediately following the closing represented approximately a 26.5% economic interest in us and 60% of the total voting power in us.

On December 19, 2014, we filed a certificate of amendment with the New York Secretary of State to change our name from “Forest Oil Corporation” to “Sabine Oil & Gas Corporation.” Our principal executive offices and corporate headquarters are located at 1415 Louisiana Street, Suite 1600, Houston, Texas 77002. Our telephone number at that address is (832) 242-9600.

Chapter 11 Filings

On July 15, 2015, we and certain of our subsidiaries, including Giant Gas Gathering LLC, Sabine Bear Paw Basin LLC, Sabine East Texas Basin LLC, Sabine Mid-Continent Gathering LLC, Sabine Mid-Continent LLC, Sabine Oil & Gas Finance Corp., Sabine South Texas Gathering LLC, Sabine South Texas LLC and Sabine Williston Basin LLC (collectively, the “Filing Subsidiaries” and, together with us, the “Debtors”), filed voluntary petitions (the “Bankruptcy Petitions”) for reorganization under the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York (the “Bankruptcy Court”). The Debtors Chapter 11 cases (the “Chapter 11 Cases”) are being jointly administered under the case styled In re Sabine Oil & Gas Corporation, et al, Case No. 15-11835. The Debtors will continue to operate their businesses as “debtors-in-possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

By certain “first day” motions filed in the Chapter 11 Cases, we obtained Bankruptcy Court approval to, among other things and subject to the terms of the orders entered by the Bankruptcy Court, pay certain employee wages, health benefits and certain other employee obligations, pay certain lienholders and forward funds to third parties, including royalty holders and other partners.

For the duration of our Chapter 11 proceedings, our operations and ability to develop and execute our business plan are subject to the risks and uncertainties associated with the Chapter 11 process. For example, negative events associated with our Chapter 11 proceedings could adversely affect our relationships with our suppliers, service providers, customers, and other third parties and our ability to retain employees, which in turn could adversely affect our operations and financial condition. For a description of these and other risks, please see “Part I, Item 1A. Risk Factors.” As a result of these risks and uncertainties, the number of our outstanding shares and shareholders, assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 proceedings, and the description of our operations, properties and capital plans included in this Annual Report may not accurately reflect our operations, properties and capital plans following the Chapter 11 process.

In particular, subject to certain exceptions, under the Bankruptcy Code, the Debtors may assume, assign, or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and certain other conditions. The rejection of an executory contract or unexpired lease is generally treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Debtors of performing their future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Counterparties to such rejected contracts or leases may assert claims against the applicable debtor's estate for such damages. The assumption of an executory contract or unexpired lease generally requires the Debtors to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with the Debtors in this Annual Report, including where applicable a quantification of our obligations under any such executory contract or unexpired lease with the Debtors, is qualified by any overriding rejection rights we have under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and the Debtors expressly preserve all of their rights with respect thereto.

Our filing of the Bankruptcy Petitions described above constitutes an event of default that accelerated our obligations under the New Revolving Credit Facility, the Term Loan Facility, the 2017 Notes and the Legacy Forest Notes. We have classified all debt as "Liabilities Subject to Compromise" in the Consolidated Balance Sheet at December 31, 2015. This debt includes unsecured and under secured obligations which are reported at the amounts expected to be allowed as claims by the Bankruptcy Court, even if they may be settled for lesser amounts. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and the reported income and expenses could be required and could be material. For additional description of the defaults present under our debt obligations, please see Note 8 within "Part II, Item 8. Financial Statements and Supplementary Data".

We are making adequate protection payments to the lenders under the New Revolving Credit Facility in an amount equal to the non-default rate of interest, fees and costs due and payable on a monthly basis under the New Revolving Credit Facility, in accordance with the cash collateral order filed with the Bankruptcy Court. Additionally, cash generated by the Company deemed to be proceeds of the oil and gas properties that represent prepetition collateral is deposited into a segregated account, which is reflected as Cash in the Consolidated Balance Sheet as of December 31, 2015, and is used solely to pay for the operations of the prepetition collateral properties.

On October 21, 2015 the Debtors filed a motion to set a bar date to assist with the claims reconciliation process. On January 26, 2016, the Debtors filed with the Bankruptcy Court a joint plan of reorganization (the "Plan of Reorganization") for the resolution of the outstanding claims against and interests in the Debtors and a disclosure statement (the "Disclosure Statement") related thereto. The Plan of Reorganization, if implemented as proposed by the Debtors, would significantly reduce our outstanding long-term debt and annual interest payments. The Disclosure Statement has not yet been approved by the Bankruptcy Court. Although the Debtors currently have the exclusive right to file a plan and solicit the appropriate votes thereon, such rights expire on February 10, 2016 and April 11, 2016, respectively. Accordingly, the Debtors have filed a motion to further extend their exclusive right to file and solicit acceptance of the Plan of Reorganization, or any other plan, through June 9, 2016 and August 9, 2016, respectively. A hearing on that motion will be held before the US Bankruptcy Court on April 7, 2016 and April 11, 2016. There can be no assurances regarding our ability to successfully develop, confirm or consummate the Plan of Reorganization, an alternative plan or reorganization or another alternative restructuring transactions, including a sale of all or substantially all of our assets, which satisfies the conditions of the Bankruptcy Code and is authorized by the Bankruptcy Court.

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Our Properties

Overview

Our properties are primarily focused in three core geographic areas:

- East Texas, targeting the Cotton Valley Sand and Haynesville Shale formations;
- South Texas, targeting the Eagle Ford Shale formation; and
- North Texas, targeting the Granite Wash formation.

As of December 31, 2015, we held interests in approximately 272,100 gross (217,000 net) acres in East Texas, 82,900 gross (53,400 net) acres in South Texas and 33,900 gross (25,300 net) acres in North Texas. As of December 31, 2015, we were the operator on 90%, 99% and 99% of our net acreage positions in East Texas, South Texas and North Texas, respectively.

The hydrocarbon content of our drilling inventory ranges from predominantly oil to entirely natural gas, providing significant optionality for our capital allocation to maximize returns in a wide variety of commodity price environments. In the near term, our capital program is expected to be focused primarily in the Cotton Valley Sand and Haynesville formations, where we have a history of development activities with consistent and reliable economic results. Our acreage in the Haynesville Shale in East Texas and our acreage in the Eagleville area in South Texas are primarily held by production.

The 2015 drilling and completion capital program associated with our properties was focused on projects that exhibited the most attractive economics based on commodity prices at that time. Full year 2015 capital expenditures were approximately $197 million, including approximately $203 million on drilling and completion activities, offset by approximately $6 million on acquisitions and other activities. Drilling and completion expenditures included approximately $144 million for the development of proved undeveloped reserves and approximately $59 million for the development of unproved reserves. Our 2016 capital expenditures are forecasted to total approximately $18 million.

Our Acquisition History

During 2013 through 2015, we successfully completed four significant transactions, including the Combination, under which we combined the respective businesses of Sabine O&G and Forest. Additionally, we purchased additional working interests in properties. In prior periods, the Company has executed farm out agreements which established our positions in the Eagle Ford Shale in South Texas and in the Granite Wash area in North Texas, and expanded our positions in the Cotton Valley Sand and Haynesville Shale areas in East Texas.

Operating Regions Associated with Our Properties

East Texas

The East Texas portion of our properties is characterized by several productive horizons, such as the Cotton Valley Sand, Haynesville Shale, Haynesville Lime, Pettet, Bossier Shale, Travis Peak and other formations. Currently, our primary operational focus in this area is directed at the Cotton Valley Sand and Haynesville Shale formations. We believe the Cotton Valley Sand formation is a well-understood play given its history of extensive vertical development, making it a predictable and repeatable development opportunity. Geologically, the Cotton Valley Sand formation is a thick, consolidated sand formation at depths ranging from approximately 7,800 feet to 10,800 feet, and has had over 400 horizontal wells drilled in the play in our properties’ core operating area.

Our other primary target in East Texas, the Haynesville Shale, lies approximately 1,500 feet below the Cotton Valley Sand formation. The Haynesville Shale is a Jurassic age reservoir, which is as much as 300 feet thick, is composed of organic-rich black shale and is found under much of the East Texas acreage position associated with our properties at depths ranging from approximately 11,000 feet to 12,000 feet. We believe this Haynesville Shale position represents a large gas resource, which is strategically positioned geographically to benefit from a growing demand for domestic natural gas.

Our East Texas properties are primarily located in Harrison, Panola and Rusk Counties in Texas and Red River Parish in Northern Louisiana with estimated proved reserves of 623 Bcfe as of December 31, 2015, of which 78% is natural gas and 74% is developed. As of December 31, 2015 our properties were producing from 1,462 wells in East Texas, and we operated 1,251, or 86%, of those wells. Average net daily production in East Texas from our properties for the three months ended December 31, 2015 was 194 MMcfe/d.

Primary operations are in the following areas for which a significant portion of our Cotton Valley Sand and Haynesville Shale acreage overlaps geographically, representing two distinct targets and development opportunities:

- Cotton Valley Sand—As of December 31, 2015, approximately 151,000 gross (101,300 net) acres of this East Texas position was prospective for the liquids-rich Cotton Valley Sand formation, 96% of which was held by production. As of December 31, 2015, our properties produced from 110 horizontal and 972 vertical wells in the Cotton Valley Sand, and we operated 947, or 88%, of those wells.
- Haynesville Shale—As of December 31, 2015, approximately 98,900 gross (71,800 net) acres of our East Texas position was prospective for the Haynesville Shale, 84% of which was held by production. Approximately 8,000 gross (7,900 net) of this acreage is located in Red River Parish, Louisiana. As of December 31, 2015, we produced from 132 wells in the Haynesville Shale, and we operated 110, or 83%, of those wells.

South Texas

The South Texas assets associated with our properties are primarily prospective for the Eagle Ford Shale formation. The first horizontal wells in the Eagle Ford Shale were drilled in 2008, and the play has become one of the largest unconventional oil producing plays in North America. The formation is characterized as having low geologic risks and repeatable drilling opportunities. Geologically, the Eagle Ford Shale is a thick, organic-rich, carbonaceous shale reservoir found at depths ranging from 4,000 feet to 13,000 feet, and in much of the deeper portions of the play is over-pressurized, enhancing well performance.

In South Texas, as of December 31, 2015, our properties represented interests in approximately 82,900 gross (53,400 net) acres in DeWitt, Lavaca and Gonzales Counties prospective for the Eagle Ford Shale, approximately 69% of which was held by production. This area had estimated proved reserves of 62 Bcfe as of December 31, 2015, of which 64% was oil or NGLs and 100% was developed. As of December 31, 2015, our properties were producing from 186 wells in South Texas, and we operated 183, or 98%, of those wells. Average net daily production associated with our properties in South Texas for the three months ended December 31, 2015 was 36 MMcfe/d.

Primary operations are in the following areas:

- Sugarkane Area—As of December 31, 2015, the Sugarkane area included approximately 2,800 gross (2,500 net) acres, 99% of which was held by production. As of December 31, 2015, our properties were producing from 20 horizontal wells, 19 of which we operated.
- Shiner Area—As of December 31, 2015, the Shiner area included approximately 32,400 gross (27,500 net) acres, 40% of which was held by production. As of December 31, 2015, our properties were producing from 48 horizontal wells, 47 of which we operated.
- Eagleville Area—As of December 31, 2015, the Eagleville area included approximately 47,700 gross (23,300 net) acres, 99% of which was held by production. As of December 31, 2015, our properties were producing from 115 horizontal wells, all 115 of which we operated.

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North Texas

The North Texas properties are located in the Anadarko Basin with the Granite Wash as the target horizon. The Granite Wash is a series of stacked, silty-sandy deposits found at depths of 8,500 feet to 11,000 feet that were laid down throughout the Pennsylvanian era and into early Permian time, and is over 3,000 feet thick.

In North Texas, as of December 31, 2015, we held rights to develop approximately 33,900 gross (25,300 net) acres primarily in Roberts County in Texas, approximately 23% of which was held by production. The North Texas acreage as of December 31, 2015 includes approximately 18,850 net acres that are subject to a continuous drilling clause which requires us to drill one gross well every 180 days to hold the entire approximately 18,850 net acre position.

This area has estimated proved reserves of 17 Bcfe as of December 31, 2015, of which 59% was oil or NGLs and 84% was developed. As of December 31, 2015, our properties were producing from 44 wells in North Texas, and we operated 40, or 91% of those wells. Average net daily production in North Texas for the three months ended December 31, 2015 was 20 MMcfe/d.

Other

As of December 31, 2015, our position outside of our three core geographic areas included approximately 23,900 gross (11,200 net) acres primarily in North Dakota, Mississippi and Wyoming.

Estimated Proved Reserves

The information with respect to our estimated proved reserves as of December 31, 2015 and December 31, 2014 presented below has been prepared by our independent petroleum engineering firm, Ryder Scott Company, L.P. (“Ryder Scott”), in accordance with rules and regulations of the Securities and Exchange Commission (“SEC”) applicable to companies involved in oil and natural gas producing activities in effect at the applicable time. The reports of Ryder Scott are dated February 5, 2016 and January 20, 2015. The reports of Ryder Scott are filed as Exhibits 99.1 and 99.2 to this Annual Report on Form 10-K. These proved reserve estimates as of December 31, 2015 and December 31, 2014 were prepared using the unweighted average of the historical first-day-of-the-month prices for the prior twelve months. It should not be assumed that the present value of future net revenues from our proved reserves is the current market value of our estimated reserves. Actual future prices and costs may differ materially from those used in the present value estimates.

The following table sets forth information regarding our estimated proved reserves, by region, for the periods indicated. The information in the table does not give any effect to or reflect commodity hedges. Although the SEC’s rules also permit the presentation of estimated “probable” or “possible” reserves, we have limited our presentation to estimated proved reserves.

	At December 31,	
	2015 (1)	2014 (2)
	Proved reserves (Bcfe)	Proved reserves (Bcfe)
Operating area		
East Texas (3)	623	1,198
South Texas	62	106
North Texas	17	43

Other (4)	0	10
Total	702	1,357

(1) Data for December 31, 2015 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $50.28 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $2.58 per MMbtu for natural gas.

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(2) Data for December 31, 2014 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $94.99 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $4.35 per MMbtu for natural gas.
(3) Includes Northern Louisiana.
(4) Includes Wyoming, North Dakota and the Permian Basin.

The following table sets forth additional information regarding our estimated proved reserves at the dates indicated.

	At December 31,	
	2015 (1)	2014 (2)
Estimated proved reserves:		
Oil (MMBbl)	9.2	20.1
NGLs (MMBbl)	22.0	41.1
Natural gas (Bcf)	514.3	989.8
Total estimated proved reserves (Bcfe)	701.8	1,357.1
Proved developed producing reserves:		
Oil (MMBbl)	7.7	13.2
NGLs (MMBbl)	16.0	23.0
Natural gas (Bcf)	391.4	498.1
Total proved developed producing reserves (Bcfe)	533.5	715.4
Proved developed non-producing:		
Oil (MMBbl)	0.1	0.5
NGLs (MMBbl)	0.2	0.8
Natural gas (Bcf)	4.8	22.3
Total proved developed non-producing reserves (Bcfe)	6.4	30.0
Total proved undeveloped:		
Oil (MMBbl)	1.5	6.5
NGLs (MMBbl)	5.8	17.2
Natural gas (Bcf)	118.0	469.4
Total proved undeveloped reserves (Bcfe)	161.9	611.7
Percent developed	76.9 %	54.9 %

(1) Data for December 31, 2015 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $50.28 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $2.58 per MMbtu for natural gas.
(2) Data for December 31, 2014 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior twelve months of $94.99 per Bbl for oil and (b) Henry Hub spot market prices for the prior twelve months of $4.35 per MMbtu for natural gas.

Controls and Qualifications of Technical Persons

In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and guidelines established by the SEC, Ryder Scott, independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2014 and December 31, 2015. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers 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 met with our independent reserve engineers periodically during the period covered by the reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

The preparation of proved reserve estimates was completed in accordance with our 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 our Vice President—Corporate Engineering or under his direct supervision;
- review by our Vice President—Corporate Engineering 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;
- direct reporting responsibilities by our Vice President—Corporate Engineering to our Chief Operating Officer; and
- verification of property ownership by our land department.

Tim Pownell, Vice President—Corporate Engineering, is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Pownell is a graduate of Texas A&M University with a Bachelor of Science degree in Chemical Engineering, and obtained his MBA from the UCLA Anderson School of Management. Mr. Pownell has 25 years of energy experience and our petrotechnical staff has an average of more than 19 years of industry experience per person.

The reserves estimates shown herein have been independently estimated by Ryder Scott, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. Ryder Scott was founded in 1937 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-1580. Within Ryder Scott, the technical person primarily responsible for overseeing the estimates set forth in the Ryder Scott evaluation letters incorporated herein is Mr. Joseph E. Blankenship. Mr. Blankenship has been practicing consulting petroleum engineering at Ryder Scott since 1982. Mr. Blankenship is a Licensed Professional Engineer in the State of Texas (No. 62093) and has over 30 years of experience in petroleum engineering and in the estimation and evaluation of reserves. Mr. Blankenship graduated from the University of Alabama in 1977 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Blankenship is a member of the Society of Petroleum Engineers (“SPE”) and a member of the Society of Petroleum Evaluation Engineers (“SPEE”). Mr. Blankenship exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. Mr. Blankenship is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Technology Used to Establish Proved Reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas that 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. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. 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.

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To establish reasonable certainty with respect to our estimated proved reserves, our independent reserve engineers, Ryder Scott, employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, open hole logs, core analyses, geologic maps, available downhole and production data and seismic data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves, material balance calculations or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using pore volume calculations and performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Proved Undeveloped Reserves (PUDs)

Year Ended December 31, 2015

As of December 31, 2015, our proved undeveloped reserves totaled 1.5 MMBbls of oil, 5.8 MMBbls of NGLs and 118.0 Bcf of natural gas, for a total of 161.9 Bcfe. There were a total of 21 PUDs booked with 18, 2 and 1 wells booked in the Cotton Valley Sand, Granite Wash and Haynesville Shale, respectively.

Changes in PUDs that occurred during 2015 were primarily due to:

- negative revisions of 341,156 MMcfe primarily due to reduced rig activity due to low prices;
- the conversion of approximately 142,287 MMcfe attributable to PUDs into proved developed reserves net of revisions, a 23% conversion rate of 2014 PUD volumes; and
- additions of approximately 33,640 MMcfe in PUDs due to a combination of adjustments in PUD working interest, performance revisions and optimized well lengths.

Costs incurred relating to the development of PUDs were approximately $144 million during the twelve months ended December 31, 2015.

As of December 31, 2015, 1% of our total proved reserves were classified as proved developed non-producing.

Productive Wells

Productive wells consist of producing wells and wells mechanically capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of productive wells in which we have working interests, and net wells are the sum of our fractional working interests owned in gross wells. The following table sets forth the number of productive wells in which we owned a working interest at December 31, 2015.

	Oil		Gas	
	Gross Wells	Net Wells	Gross Wells	Net Wells
East Texas	70	65	1,392	1,168
South Texas	124	80	62	48
North Texas	41	26	3	1
Total	235	171	1,457	1,217

Drilling Activities

The table below sets forth the results of our drilling activities for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a

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reasonable rate of return. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	For the Year Ended December 31,					
	2015		2014 (1)		2013 (2)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (3)	0.0	0.0	0.0	0.0	2.0	1.3
Dry	1.0	0.8	0.0	0.0	—	—
Total Exploratory	1.0	0.8	0.0	0.0	2.0	1.3
Development Wells:						
Productive (3)	35.0	30.1	65.0	49.1	43.0	30.8
Dry	1.0	1.0	0.0	0.0	1.0	0.4
Total Development	36.0	31.1	65.0	49.1	44.0	31.2
Total Wells:						
Productive (3)	35.0	30.1	65.0	49.1	45.0	32.1
Dry	2.0	2.0	0.0	0.0	1.0	0.4
Total	37.0	32.1	65.0	49.1	46.0	32.5

(1) Drilling activities for the year ended December 31, 2014 include the results of Forest for the period beginning December 16, 2014 and ending December 31, 2014. For the period from January 1, 2014 through December 15, 2014, Forest drilled a total of 18 gross (16.3 net) productive wells.
(2) The drilling activities for the year ended December 31, 2013 relate only to those associated with the Sabine O&G Properties.
(3) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

Developed and Undeveloped Acreage

Our properties include interests in developed and undeveloped oil and natural gas acreage in the regions set forth in the table below. Also set forth in the table below, is the percentage of acreage held by production ("HBP"). These interests generally take the form of working interests in oil and natural gas leases or licenses that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2015:

	Developed acreage		Undeveloped acreage		Total acreage		HBP	
	Gross	Net	Gross	Net	Gross	Net	%	
East Texas	219,469	183,828	52,585	33,182	272,054	217,010	85	%
South Texas	65,130	36,715	17,815	16,715	82,945	53,430	69	%
North Texas	9,433	5,925	24,508	19,402	33,941	25,327	23	%
Total Acreage	294,032	226,468	94,908	69,299	388,940	295,767	77	%

Our inventory of undeveloped oil and natural gas leaseholds is comprised of three to five year term leases and leases that are held by production beyond their primary term. In most cases, the terms of the undeveloped leases can be extended by paying delay rentals or by producing oil and natural gas reserves that are discovered under those leases, however undeveloped acreage could expire subject to development requirements.

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Undeveloped Acreage Expirations

The following table sets forth the number of total net undeveloped acres as of December 31, 2015 that will expire in 2016, 2017 and 2018 unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed.

	2016	2017	2018	Total
East Texas	7,812	5,386	1,350	14,548
South Texas	11,246	4,709	189	16,144
North Texas	2,162	199	31	2,392
Total	21,220	10,294	1,570	33,084

Production, Revenues and Price History

Oil and natural gas are commodities. The prices we receive for the oil, natural gas and NGLs we produce are largely a function of market supply and demand. We are not committed to provide any material fixed or determinable quantities of oil or natural gas under any existing contracts or agreements. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. Oil and natural gas prices declined significantly in the last half of 2014 with continued weakness in 2015. A further decline or sustained depression in oil or natural gas prices could have a material adverse effect on our business, results of operations, financial condition, access to capital and ability to meet our financial commitments and other obligations. For additional information on commodity price volatility and related risks, see “Part I, Item 1A. Risk Factors.” For a description of our working capital policy, see “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Working Capital.” See “Part II, Item 8. Financial Statements and Supplementary Data” for information regarding our profits, losses and total assets relating to our production, revenues and price history.

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The following table sets forth information regarding oil and natural gas production, revenues and realized prices and production costs for the years ended December 31, 2015, 2014 and 2013. For additional information on price calculations, see information set forth in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	For the Years Ended December 31,		
	2015	2014 (1)	2013 (2)
Oil, NGLs and natural gas sales by product (in thousands):			
Oil	$ 120,996	$ 181,313	$ 132,513
NGL	41,610	62,420	59,772
Natural gas	172,378	218,630	161,938
Total	$ 334,984	$ 462,363	$ 354,223
Production data:			
Oil (MBbl)	2,786.40	2,169.52	1,403.62
NGL (MBbl))	3,168.98	2,120.56	1,842.47
Natural gas (Bcf)	66.22	49.22	44.29
Combined (Bcfe) (3)	101.95	74.96	63.77
Average prices before effects of economic hedges (4):			
Oil (per Bbl)	$ 43.42	$ 83.57	$ 94.41
NGL (per Bbl)	$ 13.13	$ 29.44	$ 32.44
Natural gas (per Mcf)	$ 2.60	$ 4.44	$ 3.66
Combined (per Mcfe) (3)	$ 3.29	$ 6.17	$ 5.55
Average realized prices after effects of economic hedges (4):			
Oil (per Bbl)	$ 60.83	$ 81.79	$ 90.49
NGL (per Bbl)	$ 13.13	$ 29.44	$ 32.44
Natural gas (per Mcf)	$ 3.26	$ 4.30	$ 4.82
Combined (per Mcfe) (3)	$ 4.19	$ 6.02	$ 6.28
Average costs (per Mcfe) (3):			
Lease operating expenses	$ 0.87	$ 0.68	$ 0.70
Marketing, gathering, transportation and other	$ 0.33	$ 0.32	$ 0.28
Production and ad valorem taxes	$ 0.17	$ 0.24	$ 0.28
General and administrative expenses	$ 0.42	$ 0.41	$ 0.43
Depletion, depreciation and amortization	$ 1.79	$ 2.53	$ 2.15

(1) Production data for the year ended December 31, 2014 include the results of Forest for the period beginning December 16, 2014 and ending December 31, 2014.
(2) Production data for the year ended December 31, 2013 relate only to those associated with the Sabine O&G Properties.
(3) Oil and NGL production was converted at 6 Mcf per Bbl to calculate combined production and per Mcfe amounts.
(4) Average prices shown in the table reflect prices both before and after the effects of our realized commodity derivative transactions. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivative transactions.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources than we do. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient rig availability, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. Our larger competitors may be able to pay more for productive oil and 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 oil and natural gas market prices. Also, our level of indebtedness may adversely affect our ability to raise additional capital to fund operations and limit our ability to fund future capital expenditures and working capital, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt or to comply with any restrictive terms of our debt. This could limit our flexibility in planning for, or reacting to, changes in our business or industry in which we operate, placing us at a competitive disadvantage compared to our competitors who are less highly leveraged and who therefore may be able to take advantage of opportunities that our leverage prevents us from exploring.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. 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.

Marketing and Significant Customers

We market the majority of the natural gas residue, crude oil, and natural gas liquids from properties we operate for both our account and the account of the other working interest owners in these properties.

In East Texas, we have approximately 85% of our NGL's under three to five year gathering and processing contracts to a variety of midstream companies. The remainder of our NGL's are being sold under gathering and processing contracts which are past their primary term with a 30 day evergreen. We sell approximately 45% of our residue under NAESB contracts on a year to year term ending October 31, 2016 at competitive market prices. The remainder of the residue is sold in conjunction with the NGL sale to the midstream companies processing our NGL's. In East Texas, our oil is sold to one purchaser under a short-term contract which is month-to-month.

In South Texas, we sell our Sugarkane NGL's under two five-year gathering and processing contracts. Our N. Shiner NGL's are sold under a five year gas services agreement. Our S. Shiner NGL's are sold under two separate five year gathering and processing agreements. We sell all our STX residue under NAESB contracts on a year-to-year term ending October 31, 2016. In South Texas, our oil is sold to two separate purchasers under short-term contracts which are month-to-month.

In North Texas, we sell our natural gas residue and NGLs production under a long-term contract to one midstream company, through an acreage dedication. Our oil is sold under a three year contract which allows us to offtake to a dedicated lease automatic custody transfer unit.

During the year ended December 31, 2015, purchases by three companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Enbridge Pipeline (East Texas) LP, NGL Crude Logistics LLC, and Laclede Energy accounted for approximately 28%, 14% and 10%. of our oil, NGLs and natural gas sales, respectively. During the year ended December 31, 2014, purchases by four companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Enbridge Pipelines, NGL Crude Logistics LLC, Laclede Energy and Eastex Crude Company accounted for approximately 13%, 12%, 12% and 10% of our oil, NGLs and natural gas sales, respectively. During the year ended December 31, 2013, purchases by three companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Eastex Crude Company, Enbridge Pipeline (East Texas) LP and CP Energy LLC accounted for approximately 19%, 16% and 11% of our oil, NGLs and natural gas sales, respectively. We believe that the loss of any of the purchasers above would not result in a material adverse effect on our ability to competitively market future oil and natural gas production.

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Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

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 oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, 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 which may be drilled in an area, and the unitization or pooling of crude natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability 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 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 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 (“FERC”), and the courts. We cannot predict when or whether any such proposals may become effective.

We believe that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, results of operations or cash flows. 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

The production of oil and natural gas 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 oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation of Oil

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could enact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. FERC regulates interstate oil pipeline

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transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, FERC reviews the appropriateness of the index level in relation to changes in industry costs. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation 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, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The open access policies implemented by FERC since the mid-1980s serve to enhance the competitive structure of the interstate natural gas pipeline industry and create a regulatory framework that puts natural gas sellers into direct contractual relations with natural gas buyers by, among other things, ensuring that the sale of natural gas is unbundled from the sale of transportation and storage services. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future.

Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act (the "NGA") and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

We cannot accurately predict how FERC's actions will impact competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are regularly pending before FERC and the courts, as the natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that any of the measures established by FERC will continue in effect or that they will not be materially altered, potentially on short notice. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission (the "CFTC") and the Federal Trade Commission. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities is done on a case by case basis. 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.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. 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.

Regulation of Pipeline Safety

Natural gas and crude oil pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 ("PSI Act") and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES Act"). The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. At present, our operations are not subject to PHMSA's integrity management regulations. We believe that our pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking and sought public comment on a number of proposed changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 report to Congress from the U.S. Government Accountability Office ("GAO"), the GAO acknowledged PHMSA's continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. Our gathering line assets only include small diameter, low-pressure pipelines. Based on current regulatory initiatives and statements made by

PHMSA, we do not expect our gathering assets to become regulated as a result of any future rulemakings related to gathering lines. However, we cannot guarantee that PHMSA will not attempt to extend its jurisdiction over our assets at some point in the future.

Environmental Regulation

Our operations are subject to stringent federal, state and local laws and regulations regulating the discharge and disposal of materials into the environment or otherwise relating to health and safety or the protection of the environment and natural resources. These laws and regulations may, among other things: (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to clean up or mitigate pollution from former and ongoing operations, such as requirements to close waste pits and plug abandoned wells, or at off-site waste disposal locations; (v) impose specific safety and health criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Numerous governmental agencies, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies (and, in some cases, private individuals), enforce these laws and regulations, which often require difficult and costly compliance measures. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, the issuance of injunctions limiting or prohibiting our activities, or the imposition of remedial obligations. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of that person. Adherence to these regulatory requirements increases our cost of doing business and consequently affects our profitability.

New programs and changes in existing regulatory programs are anticipated, some of which include regulations related to the management of natural occurring radioactive materials, oil and natural gas exploration and production, waste management, and underground injection of waste material and the regulation of hydraulic fracturing. Environmental laws and regulations have been subject to frequent changes over the years, and the trend has been the imposition of more stringent requirements. While we believe that we are in substantial compliance with current applicable environmental laws and regulations, changes in existing or new laws or regulations could have a material adverse effect on our financial condition and results of operations. From time to time, we may be involved in lawsuits related to alleged pollution or environmental damage. In addition, we cannot assure you that we will not incur significant costs as a result of releases or spills in the course of our operations. For example, following the closing of the Combination, we inherited potential liability for several legacy lawsuits filed against Forest. Adverse judgments against us related to these matters could have a material impact on our business. Please see "Part I, Item 3. Legal Proceedings" for more information.

The following is a summary of select existing and proposed environmental and occupational health and safety laws, as amended from time to time, to which our business operations are or may be subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Wastes

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes and their implementing regulations, regulate the generation, storage, treatment, transportation, disposal and cleanup of certain hazardous and non-hazardous solid wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or natural gas, including naturally occurring radioactive material, if properly handled, are exempt from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA's less stringent nonhazardous solid waste provisions, state laws or other laws. However, it is possible that certain oil and natural gas exploration, development and production wastes now classified by regulatory agencies as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in August 2015, nonprofit environmental groups filed a notice of intent to sue the EPA regarding its failure to review the exemption. A loss of the RCRA hazardous waste exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may become regulated as hazardous wastes if such wastes have hazardous characteristics.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law and comparable state laws impose liability, without regard to fault or legality of conduct, on classes of persons considered to be responsible for the release of certain "hazardous substances" into the environment. These persons can include the current and past owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible parties the costs they incur. In addition, neighboring landowners and other third-parties may file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although petroleum, including crude oil or any fraction thereof, is not a CERCLA "hazardous substance," we generate materials in the course of our operations that may be regulated as CERCLA hazardous substances and thus may be subject to joint and several liability for the costs to clean up sites at which these hazardous substances have been released into the environment.

We currently own, lease, operate and/or have acquired, and have in the past owned, leased operated, numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges and Releases

Our operations are also subject to the Clean Water Act (the "CWA") and analogous state laws. The CWA and similar state laws regulate discharges of wastewater, oil, and other pollutants to regulated water bodies, such as lakes, rivers, wetlands, and streams. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the analogous state agency. In addition, spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The CWA and analogous state laws also require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities, and also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. We believe that we will be able to obtain, or be included under, these permits, where necessary, and would be able to make whatever minor modifications to existing facilities and operations are necessary to comply with CWA requirements and that such modifications would not have a material effect on us. Failure to obtain or comply with permits or other CWA could result in administrative, civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages.

The Oil Pollution Act of 1990 ("OPA"), which amended the CWA, imposes ongoing requirements on owners and operators of facilities that handle certain quantities of oil, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental clean-up and restoration costs that could be incurred in connection with an oil spill. In addition, OPA establishes strict liability for owners and operators of facilities that are the site of a release of oil into regulated waters. If a release into regulated waters occurs, we could be liable for clean-up costs, natural resources damages and public and private damages.

Hydraulic Fracturing

Hydraulic fracturing is an essential and common practice in the oil and natural gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the well bore. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. While hydraulic fracturing is generally exempt from regulation the Safe Drinking Water Act's ("SDWA") Underground Injection Control ("UIC") and has historically been regulated by

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state oil and natural gas commissions, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities. For example, the EPA published revised permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. Also, in May 2014, the EPA published an advance notice of proposed rulemaking under the Toxic Substances Control Act seeking stakeholder input on development of a requirement regarding disclosure of information on chemical substances and mixtures used in hydraulic fracturing. The public comment period on the EPA's advance notice ended in September 2014, and a final notice of proposed rulemaking is expected in 2016. In addition, in April 2015, the EPA proposed regulations under the Clean Water Act to regulate wastewater discharges from hydraulic fracturing to publicly-owned treatment works (the final rule is expected to be issued in 2016). In addition to rulemakings, increased scrutiny of the oil and natural gas industry may occur as a result of the EPA's FY2014-2016 National Enforcement Initiative, "Ensuring Energy Extraction Activities Comply with Environmental Laws," through which the EPA will 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; starting October 1, 2016, this initiative will continue for three more fiscal years.

In March 2015, the federal Bureau of Land Management published a final rule governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. However, a federal judge has granted a preliminary injunction preventing enforcement of the rules.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater in 2011 and issued a draft assessment for public comment and peer review in June 2015; the assessment is expected to be finalized in 2016. The draft assessment concluded that hydraulic fracturing has not led to widespread, systemic impacts on drinking water resources, but it does have the potential to impact drinking water resources; however, this conclusion has recently been criticized by the EPA's Science Advisory Board. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

In addition, the U.S. Congress has from time to time considered the adoption of legislation to provide for federal regulation of the hydraulic fracturing or to require disclosure of the chemicals used in the hydraulic fracturing process. Furthermore, some states, including Texas, have adopted or are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities, or that ban hydraulic fracturing altogether. Some local governments have also adopted ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Any additional federal, state or local restrictions on hydraulic fracturing that may be imposed in areas where we conduct business could result in substantial incremental operating, capital and compliance costs as well as delay our ability to develop oil and natural gas reserves.

Underground Injection Wells

Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The disposal of oil and natural gas wastes into underground injection wells are subject to the SDWA's UIC program and analogous state programs. EPA directly administers the UIC program in some states and in others it delegates administration to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. In response to recent seismic events near underground injection wells used for the disposal

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of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity. For example, in 2015, a U.S. Geological Survey report identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In response to these concerns, regulators in some states have shut down or imposed moratoria on the use of such injection wells and are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") on October 28, 2014, adopted new oil and gas permit rules for wells used to dispose of saltwater and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Air Emissions

The federal Clean Air Act (the "CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. Our operations are in certain circumstances and locations subject to permitting requirements and restrictions under these statutes for emissions of air pollutants.

Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in January 2013, the EPA published revised regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The revised rule requires management practices for all covered engines and requires the installation of oxidation catalysts or non-selective catalytic reduction equipment on larger equipment at sites that are not deemed "remote" under the rule. We believe our operations are in substantial compliance with the requirements of this rule.

In addition, in 2012, the EPA issued final rules under the CAA that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants programs. These rules restrict volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non wildcat and non delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. "Other" wells, however, must use reduced emission completions, also known as "green completions," with or without combustion devices. The capture of flowback emissions is required only after the facility's processing system can be brought to pressure. These regulations also establish specific requirements regarding emissions from production related wet seal and reciprocating compressors, pneumatic controllers, and storage vessels. The EPA received numerous requests for reconsideration of these rules, and court challenges to the rules were also filed. The EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests. For example, on December 19, 2014, the EPA finalized amendments and clarifications to the NSPS rules, including, for example, updates and clarifications to requirements related to well completion activities, storage tanks, and leak detection. To date, our costs to comply with the NSPS have not been material. In September 2015, the EPA proposed updates to the NSPS rules that would impose volatile organic compound emissions limits on certain oil and natural gas operations that were previously unregulated, including hydraulically fractured oil wells, as well as methane emissions limits for certain new or modified oil and natural gas emissions sources (the rules are expected to be finalized in June 2016). In addition, the EPA published a final regulation on October 1, 2015 that reduces the National Ambient Air Quality Standard for ozone to between 65 to 70 parts per billion ("ppb") for both the 8 hour primary and secondary standards protective of public health and public welfare. These regulations, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities, or utilize specific equipment or technologies to control emissions. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Climate Change

The EPA has determined that emissions of greenhouses gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted various regulations regarding GHGs under existing provisions of the CAA. For example, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations. Further, in 2015, the EPA finalized a rule that requires reporting of GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The expansion of the EPA's GHG reporting program could result in increased compliance costs.

The EPA also recently proposed new regulations that set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45% from 2012 levels by 2025; the regulations are expected to be finalized in 2016. To aid in these efforts, in January 2016, the federal Bureau of Land Management proposed rules to reduce methane emissions from venting, flaring and leaking on public lands. In addition, the Clean Power Plan, which was announced in August 2015, seeks to reduce carbon dioxide emissions by 32 percent from 2005 levels by 2030; however, on February 9, 2016, the U.S. Supreme Court stayed the implementation of the plan while it is being challenged in court. Furthermore, the U.S. is a party to the Paris Agreement adopted in December 2015 to reduce global greenhouse emissions.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Threatened and Endangered Species

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, as well as migratory birds. We may conduct operations in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered may exist. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of threatened or endangered species. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS is required to make a determination on listing of more than 250 species as endangered or threatened under the Endangered Species Act ("ESA") by no later than completion of the agency's 2017 fiscal year. For example, in March 2014, FWS listed the lesser prairie chicken as a threatened species under the ESA. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising

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from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Related Insurance

We maintain an insurance program designed to provide coverage for our property and casualty exposures. Our risk management program provides coverage types, limits, and deductibles commensurate with companies of comparable size and with similar risk profiles. As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. As hydraulic fracturing is a key component of our operational strategy, we maintain Claims Made Pollution Liability Insurance, which provides coverage for long-term gradual seepage pollution events. A loss in connection with our oil and natural gas operations could have a material adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies is inadequate to cover any such loss.

Employees

As of December 31, 2015, we had 146 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory. In connection with our bankruptcy filing and liquidity constraints, we have performed layoffs throughout 2015 and into the first quarter of 2016. We continue to monitor the best allocation of our capital to promote enterprise value, including any cost-reducing cuts to our general and administrative expenses.

Geographical Data

We operate in one industry segment, oil and gas exploration and production, and have one reportable geographical business segment, the United States.

Available Information

We are required to file any annual, quarterly and current reports, proxy statements and certain other information with the SEC. 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 http://www.sec.gov.

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We also make available on our website (www.sabineoil.com) all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Financial Code of Ethics and Regulation FD Policy are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to 1415 Louisiana, Suite 1600, Houston, Texas 77002, attention Secretary. Information contained on our website is not incorporated by reference into this Annual Report on Form 10 K.

Legal Proceedings

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but our management team does not expect the outcome of pending or threatened legal matters to have a material adverse impact on our financial condition. Please see “Part I, Item 3. Legal Proceedings” for more information.

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Item 1A. Risk Factors

The following are certain risk factors that affect our business, financial condition, results of operations and cash flows. Many of these risks are beyond our control. These risk factors should be considered in connection with evaluating the forward-looking statements contained in this Annual Report on Form 10-K. The risks and uncertainties described below are not the only ones that we face. If any of the events described below were to actually occur, our business, financial condition, results of operations and cash flows could be adversely affected and our results could differ materially from expected and historical results, any of which may also adversely affect the holders of our stock.

We have filed voluntary petitions for relief under the Bankruptcy Code and are subject to the risks and uncertainties associated with bankruptcy cases.

We have filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. For the duration of the Chapter 11 Cases, our business and operations will be subject to various risks, including but not limited to the following:

- Our ability to develop, file and complete a Chapter 11 plan of reorganization, particularly during the exclusivity period (i.e. in general, the period in which we have the exclusive right to file a Chapter 11 plan of reorganization);
- Our ability to obtain Bankruptcy Court, creditor and regulatory approval of a Chapter 11 plan of reorganization in a timely manner;
- Our ability to obtain Bankruptcy Court approval with respect to motions in the Chapter 11 Cases and the outcomes of Bankruptcy Court rulings and of the Chapter 11 Cases in general;
- Risks associated with third party motions in the Chapter 11 Cases, which may interfere with our business operations or our ability to propose and/or complete a Chapter 11 plan of reorganization;
- Increased costs related to the Chapter 11 Cases and related litigation;
- A loss of, or a disruption in the materials or services received from, suppliers, contractors or service providers with whom we have commercial relationships;
- Potential increased difficulty in retaining and motivating our key employees through the process of reorganization, and potential increased difficulty in attracting new employees;
- Significant time and effort required to be spent by our senior management in dealing with the bankruptcy and restructuring activities rather than focusing exclusively on business operations;

We are also subject to risks and uncertainties with respect to the actions and decisions of creditors and other third parties who have interests in our Chapter 11 Cases that may be inconsistent with our plans. These risks and uncertainties could affect our business and operations in various ways and may significantly increase the duration of the Chapter 11 Cases. Because of the risks and uncertainties associated with Chapter 11 Cases, we cannot predict or quantify the ultimate impact that events occurring during the Chapter 11 Cases may have on our business, cash flows, liquidity, financial condition and results of operations, nor can we predict the ultimate impact that events occurring during the Chapter 11 Cases may have on our corporate or capital structure.

We believe it is highly likely that the shares of our existing common stock will be cancelled in our Chapter 11 proceedings.

We have a significant amount of indebtedness that is senior to our existing common stock in our capital structure. As a result, we believe that it is highly likely that the shares of our existing common stock will be cancelled in our Chapter 11 proceedings and will be entitled to a limited recovery, if any. Any trading in shares of our common stock during the pendency of the Chapter 11 proceedings is highly speculative and poses substantial risks to purchasers of shares of our common stock.

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Operating under Bankruptcy Court protection for a long period of time may harm our business.

Our future results are dependent upon the successful confirmation and implementation of a plan of reorganization. A long period of operations under Bankruptcy Court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. So long as the proceedings related to the Chapter 11 proceedings continue, our senior management will be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on our business operations. A prolonged period of operating under Bankruptcy Court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, the longer the proceedings related to the Chapter 11 proceedings continue, the more likely it is that our customers and suppliers will lose confidence in our ability to reorganize our businesses successfully and seek to establish alternative commercial relationships.

Furthermore, so long as the Chapter 11 proceedings continue, we will be required to incur substantial costs for professional fees and other expenses associated with the administration of the Chapter 11 proceeding. The Chapter 11 cases may also require us to seek debtor-in-possession financing to fund operations. If we are unable to obtain such financing on favorable terms or at all, our chances of successfully reorganizing our business may be seriously jeopardized, the likelihood that we instead will be required to liquidate our assets may be enhanced, and, as a result, any securities in the debtor could become further devalued or become worthless.

Furthermore, we cannot predict the ultimate amount of all settlement terms for the liabilities that will be subject to a plan of reorganization. Even once a plan of reorganization is approved and implemented, our operating results may be adversely affected by the possible reluctance of prospective lenders and other counterparties to do business with a company that recently emerged from Chapter 11 proceedings.

We may not be able to obtain confirmation of a Chapter 11 plan of reorganization.

On January 26, 2016, the Debtors filed with the Bankruptcy Court a joint plan of Reorganization (the “Plan of Reorganization”) for the resolution of the outstanding claims against and interests in the Debtors and a disclosure statement (the “Disclosure Statement”) related thereto. The Plan of Reorganization, if implemented as proposed by the Debtors, would significantly reduce our outstanding long-term debt and annual interest payments. To emerge successfully from Bankruptcy Court protection as a viable entity, we must meet certain statutory requirements with respect to adequacy of disclosure with respect to the Plan of Reorganization, solicit and obtain the requisite acceptances of such Plan of Reorganization and fulfill other statutory conditions for confirmation of such Plan of Reorganization, most of which have not occurred to date. The confirmation process is subject to numerous, unanticipated potential delays, including a delay in the Bankruptcy Court’s commencement of the confirmation hearing regarding our Plan of Reorganization.

We may not receive the requisite acceptances of constituencies in these Chapter 11 proceedings to confirm or consummate the Plan of Reorganization, an alternative plan of reorganization or another alternative restructuring transaction, including a sale of all or substantially all of our assets, which satisfies the condition of the Bankruptcy Code and is authorized by the Bankruptcy Court. Even if the requisite acceptances of our Plan of Reorganization are received, the Bankruptcy Court may not confirm the Plan of Reorganization. The precise requirements and evidentiary showing for confirming a plan, notwithstanding its rejection by one or more impaired classes of claims or equity interests, depends upon a number of factors including, without limitation, the status and seniority of the claims or equity interests in the rejecting class (e.g., secured claims or unsecured claims, subordinated or senior claims, preferred or common stock).

If a Chapter 11 plan of reorganization is not confirmed by the Bankruptcy Court, it is unclear whether we would be able to reorganize our business and what, if anything, holders of claims against us would ultimately receive with respect to their claims.

Even if a Chapter 11 plan of reorganization is consummated, we will continue to face risks.

Even if a Chapter 11 plan of reorganization is consummated, we will continue to face a number of risks, including certain risks that are beyond our control, such as further deterioration or other changes in economic conditions, changes

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in our industry, potential revaluing of our assets due to Chapter 11 proceedings, changes in consumer demand for, and acceptance of, our oil and gas and increasing expenses. Some of these concerns and effects typically become more acute when a case under the Bankruptcy Code continues for a protracted period without indication of how or when the case may be completed. As a result of these risks and others, there is no guaranty that the Plan of Reorganization or any other plan of reorganization will achieve our stated goals.

In addition, at the outset of the Chapter 11 proceedings, the Bankruptcy Code gives the debtor the exclusive right to file and solicit acceptance of the Plan of Reorganization and prohibits creditors, equity security holders and others from filing or soliciting a plan for a certain period of time. To date, we have retained the exclusive right to propose the Plan of Reorganization, and, on December 16, 2015, the Bankruptcy Court granted a request to extend our exclusive rights to file and solicit acceptance of the Plan of Reorganization through February 10, 2016, and April 11, 2016, respectively. The Debtors have filed a motion to further extend their exclusive rights to file and solicit acceptance of the Plan of Reorganization through June 9, 2016 and August 9, 2016, respectively. If the Bankruptcy Court terminates that right, however, or the exclusivity period expires, there could be a material adverse effect on our ability to achieve confirmation of the Plan of Reorganization in order to achieve our stated goals.

Furthermore, even if our debts are reduced or discharged through the Plan of Reorganization, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business after the completion of the Chapter 11 process. Adequate funds may not be available when needed or may not be available on favorable terms.

We have substantial liquidity needs and may be required to seek additional financing. If we are unable to obtain financing on satisfactory terms or maintain adequate liquidity, our ability to replace our proved reserves or to maintain current production levels and generate revenue will be limited.

Our principal sources of liquidity historically have been equity contributions, borrowings under the New Revolving Credit Facility, net cash provided by operating activities, net proceeds from the issuance of the 2017 Notes and proceeds from the Term Loan Facility. Our capital program will require additional financing above the level of cash generated by our operations to fund growth. If our cash flow from operations remains depressed or decreases as a result of lower commodity prices or otherwise, our ability to expend the capital necessary to replace our proved reserves, maintain our leasehold acreage or maintain current production may be limited, resulting in decreased production and proved reserves over time. In addition, drilling activity may be directed by our partners in certain areas and we may have to forfeit acreage if we do not have sufficient capital resources to fund our portion of expenses.

We face uncertainty regarding the adequacy of our liquidity and capital resources and have extremely limited, if any, access to additional financing. In addition to the cash requirements necessary to fund ongoing operations, we have incurred significant professional fees and other costs in connection with preparation for and consummation of the Chapter 11 proceedings. We cannot assure you that cash on hand and cash flow from operations will be sufficient to continue to fund our operations and allow us to satisfy our obligations related to the Chapter 11 Cases until we are able to emerge from Chapter 11. We face additional uncertainty regarding the ability to emerge successfully from Chapter 11 and to obtain adequate liquidity to finance our capital program subsequent to emergence from Chapter 11.

Our liquidity, including our ability to meet our ongoing operational obligations, is dependent upon, among other things: (i) our ability to comply with the terms and conditions of the final cash collateral order entered by the Bankruptcy Court on September 16, 2015 in connection with the Chapter 11 proceedings, (ii) our ability to maintain adequate cash on hand, (iii) our ability to generate cash flow from operations, (iv) our ability to develop, confirm and consummate a Chapter 11 plan or other alternative restructuring transaction, and (v) the cost, duration and outcome of the Chapter 11 proceedings. Our ability to maintain adequate liquidity depends in part upon industry conditions and general economic, financial, competitive, regulatory and other factors beyond our control. In the event that cash on hand and cash flow from operations is not sufficient to meet our liquidity needs, we may be required to seek additional financing. We can provide no assurance that additional financing would be available or, if available, offered to us on acceptable terms. Our access to additional financing is, and for the foreseeable future will likely continue to be, extremely limited if it is available at all. Our long-term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time.

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As a result of the Chapter 11 Cases, our historical financial information may be volatile and not be indicative of our future financial performance.

During the Chapter 11 proceedings, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities and expenses, contract terminations and rejections, and claims assessments and may significantly impact our consolidated financial statements. As a result, our historical financial performance may not be indicative of our financial performance after the date of the bankruptcy filing.

Our capital structure will likely be significantly altered under any Chapter 11 plan confirmed by the Bankruptcy Court. Under fresh-start accounting rules that may apply to us upon the effective date of a Chapter 11 plan, our assets and liabilities would be adjusted to fair value, which could have a significant impact on our financial statements. Accordingly, if fresh-start accounting rules apply, our financial condition and results of operations following our emergence from Chapter 11 would not be comparable to the financial condition and results of operations reflected in our historical financial statements. In connection with the Chapter 11 Cases and the development of a Chapter 11 plan, it is also possible that additional restructuring and related charges may be identified and recorded in future periods. Such charges could be material to our consolidated financial position, liquidity and results of operations.

We may be subject to claims that will not be discharged in the Chapter 11 proceedings, which could have a material adverse effect on our financial condition and results of operations.

The Bankruptcy Court provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation. With few exceptions, all claims that arose prior to July 15, 2015 or before confirmation of the plan of reorganization (i) would be subject to compromise and/or treatment under the plan of reorganization and/or (ii) would be discharged in accordance with the Bankruptcy Code and the terms of the plan of reorganization. Any claims not ultimately discharged through a plan of reorganization could be asserted against the reorganized entities and may have an adverse effect on our financial condition and results of operations on a post-reorganization basis.

Transfers of our equity, or issuances of equity in connection with our Chapter 11 proceedings, may impair our ability to utilize our federal income tax net operating loss carryforwards in future years.

Under federal income tax law, a corporation is generally permitted to deduct from taxable income net operating losses carried forward from prior years. We have net operating loss carryforwards of approximately $1.0 billion as of December 31, 2015. Our ability to utilize our net operating loss carryforwards to offset future taxable income and to reduce federal income tax liability is subject to certain requirements and restrictions. If we experience an “ownership change,” as defined in section 382 of the Internal Revenue Code, then our ability to use our net operating loss carryforwards may be substantially limited, which could have a negative impact on our financial position and results of operations. Generally, there is an “ownership change” if one or more shareholders owning 5% or more of a corporation’s common stock have aggregate increases in their ownership of such stock of more than 50 percentage points over the prior three-year period. Following the implementation of a plan of reorganization, it is possible that an “ownership change” may be deemed to occur. Under section 382 of the Internal Revenue Code, absent an application exception, if a corporation undergoes an "ownership change," the amount of its net operating losses that may be utilized to offset future taxable income generally is subject to an annual limitation.

We may experience increased levels of employee attrition as a result of the Chapter 11 Cases.

As a result of the Chapter 11 Cases, we may experience increased levels of employee attrition, and our employees likely will face considerable distraction and uncertainty. A loss of key personnel or material erosion of employee morale could adversely affect our business and results of operations. Our ability to engage, motivate and retain key employees or take other measures intended to motivate and incent key employees to remain with us through the pendency of the Chapter 11 Cases is limited by restrictions on implementation of incentive programs under the Bankruptcy Code. The loss of services of members of our senior management team could impair our ability to execute our strategy and implement operational initiatives, which would be likely to have a material adverse effect on our financial condition, liquidity and results of operations.

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Oil, natural gas and NGLs prices are volatile. The recent decline in oil, natural gas and NGLs prices has adversely affected our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations and rate of growth depend primarily upon the prices we receive for our oil and natural gas production, and the carrying value of our oil and natural gas properties is dependent upon prevailing prices for oil, natural gas and NGLs. Oil, natural gas and NGLs prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current economic and geopolitical conditions. The New York Mercantile Exchange ("NYMEX") natural gas prices during 2015 ranged from a high of $3.32 to a low of $1.63 per MMbtu and the NYMEX oil prices during 2015 ranged from a high of $61.36 to a low of $34.55 per Bbl. Thus far in 2016, commodity prices have continued to be significantly depressed and volatile, with NYMEX natural gas prices ranging from a high of $2.54 to a low of $1.49 per MMbtu and the NYMEX oil prices ranging from a high of $38.51 to a low of $26.19 per Bbl through March 21, 2016. This low commodity price environment and price volatility also affects the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

The speed and severity of the decline in oil and gas prices during 2015 and the continued lower prices in the first quarter of 2016 has adversely affected our results of operations and our estimates of our proved oil and natural gas reserves. Continued periods of depressed commodity prices or further price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. Sustained low commodity prices will further adversely affect our revenues, net income, cash flows, proved reserves and our ability to fund capital expenditures.

Prices for oil, natural gas and NGLs may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the regional, domestic and foreign supply of oil and natural gas;
- uncertainty in capital and commodities markets;
- the price of foreign imports;
- the ability and willingness of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries, including the Middle East, Africa, South America and Russia including the imposition of trade sanctions;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas and alternative fuels;
- variations between product prices at sales points and applicable index prices; and
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East.

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We have significant exposure to fluctuations in commodity prices since none of our estimated future production is covered by commodity derivatives and we may not be able to enter into commodity derivatives covering our estimated future production on favorable terms or at all.

In the past, we have entered into financial commodity derivative contracts to mitigate the potential negative impact on cash flow caused by changes in oil and natural gas prices. However, as a result of certain events of default under our derivative contracts, all our derivative contracts have been terminated. Subsequent to the termination of these derivative contracts, we have not entered into additional derivative contracts. During the Chapter 11 proceedings, our ability to enter into new commodity derivatives covering additional estimated future production will be dependent upon either entering into unsecured hedges or obtaining Bankruptcy Court approval to enter into secured hedges. As a result, we may not be able to enter into additional commodity derivatives covering our production in future periods on favorable terms or at all. If we cannot or choose not to enter into commodity derivatives in the future, we could be more affected by changes in commodity prices than our competitors who engage in hedging arrangements. Our inability to hedge the risk of low commodity prices in the future, on favorable terms or at all, could have a material adverse impact on our business, financial condition and results of operations.

If we are able to enter into any commodity derivatives, they may limit the benefit we would receive from increases in commodity prices. These arrangements would also expose us to risk of financial losses in some circumstances, including the following:

- our production could be materially less than expected; or
- the counterparties to the contracts could fail to perform their contractual obligations.

If our actual production and sales for any period are less than the production covered by any commodity derivatives (including reduced production due to operational delays) or if we are unable to perform our exploration and development activities as planned, we might be required to satisfy a portion of our obligations under those commodity derivatives without the benefit of the cash flow from the sale of that production, which may materially impact our liquidity. Additionally, if market prices for our production exceed collar ceilings or swap prices, we would be required to make monthly cash payments, which could materially adversely affect our liquidity.

The trustee for our 2019 Notes has asserted certain claims against us related to the Combination.

On February 26, 2015, we were served with a complaint (the “Complaint”) concerning the indenture that governs our 2019 Notes that generally alleges that certain events of default had occurred with respect to the 2019 Notes due to the Combination. Specifically, the Complaint alleges that the Combination constituted a change of control under the indenture which requires us to offer to purchase the 2019 Notes at 101% of the outstanding principal, plus accrued and outstanding interest of the notes. We also received a notice of default and acceleration from the Trustee with respect to the 2019 Notes containing similar allegations. We believe these allegations against us are without merit and intend to vigorously defend against such claims and pursue any and all defenses available. We are separately evaluating potential claims that we may assert against the trustee for the 2019 Notes for any and all losses we may suffer as a result of the complaint or notice. We can provide no guarantee that any such claims, if brought by us, will be successful or, if successful, that the responsible parties will have the financial resources to address any such claims. Furthermore, additional claims, lawsuits, or proceedings may be filed or commenced arising out of the indentures to which we are a party and with respect to the Combination.

As a result of the pending bankruptcy proceedings, this matter is currently stayed.

Our common stock is no longer listed on a national securities exchange and is quoted only in over-the-counter markets, which carries substantial risks and could continue to negatively impact our stock price, volatility and liquidity.

Upon the closing of the Combination, the New York Stock Exchange (the “NYSE”) suspended trading in our common stock and commenced delisting proceedings due to our failure to meet the initial listing standards under Rule 102.01 of the NYSE Listed Company Manual. On December 17, 2014, our common stock began trading over the counter on the OTCQB Marketplace (the “OTCQB”) under the ticker symbol “FSTO” and later under the ticker symbol

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"SOGCQ." Additionally, as a result of the filing of the Bankruptcy Petitions, the Company's common stock can no longer be traded on the OTCQB Marketplace and is now trading on the OTC Pink Marketplace. We continue to file periodic reports with the SEC in accordance with the requirements of Section 12 (g) of the Exchange Act.

Our delisting from the NYSE and commencement of trading on the OTC Pink Marketplace has resulted and may continue to result in a reduction in some or all of the following, each of which could have a material adverse effect on our stockholders:

- the liquidity of our common stock;
- the market price of shares of our common stock;
- our ability to obtain financing for the continuation of our operations;
- the number of institutional and other investors that will consider investing in shares of our common stock;
- the number of market makers in shares of our common stock;
- the availability of information concerning the trading prices and volume of shares of our common stock; and
- the number of broker-dealers willing to execute trades in shares of our common stock.

Estimates of reserves and future net cash flows are not precise. The actual quantities of our reserves and future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of reserves and future net cash flows therefrom. Our estimates of reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate. Petroleum engineering is a subjective process of estimating accumulations of oil or natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the quality, quantity and interpretation of available relevant data;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance, ad valorem and excise taxes, development costs, and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

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The prices used in calculating our estimated proved reserves and the estimated discounted future net cash flows from proved reserves are, in accordance with SEC requirements, calculated by determining the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. December 31, 2015, average prices used to calculate our estimated proved reserves and estimated discounted future net cash flows from proved reserves were $50.28 per Bbl for crude oil and $2.58 per MMbtu for natural gas. Commodity prices declined significantly throughout 2015 and if such prices do not increase significantly, it could have a negative impact on our future calculations of estimated proved reserves and the estimated discounted future net cash flows from proved reserves will be significantly lower than as of December 31, 2015. This could result in our having to remove non-economic reserves from our proved reserves in future periods.

Holding all other factors constant, if SEC pricing as of March 2016 of $46.26 per Bbl for crude oil and $2.39 per Mcf for natural gas is used in our year-end reserve estimates, our estimated discounted future net cash flows from proved reserves at December 31, 2015 would decrease by approximately $69 million, or 14%.

Actual future net cash flows also will be affected by other factors, including:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil and natural gas; and
- changes in governmental regulations or taxation.

Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor mandated by the rules and regulations of the SEC to be used in calculating discounted future net cash flows 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. Therefore, the estimates of discounted future net cash flows included in this Annual Report on Form 10-K should not be construed as accurate estimates of the current market value of our proved reserves.

Drilling for and producing oil and natural gas are risky activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on our 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. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or other services or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil, natural gas and NGL prices;
- surface access restrictions;

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- loss of title or other title related issues;
- pipe or cement failures or casing collapses;
- compliance with environmental and other government requirements;
- environmental hazards, such as natural gas leaks, groundwater contamination resulting from improper well casing and cementing, 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 or subsurface environment;
- fires, blowouts, surface craterings and explosions;
- uncontrollable flows of oils, natural gas, formation water, or well fluids;
- oil, natural gas or NGLs gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for oil and natural gas.

The occurrence of certain of these events could also affect third parties, including persons living near our operations, our employees and employees of our contractors, leading to injuries or death or property damage. As a result, we face the possibility of liabilities from these events that could adversely affect our business, financial condition and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition 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. The rate of decline will change if production from existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. 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.

Drilling locations that we have identified may not yield oil, natural gas or NGLs in commercially viable quantities.

Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. It is impossible to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our identified drilling location inventories are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our business strategy. Our ability to drill and develop these locations depends on a number of factors, some of which are beyond our control,

including the availability and cost of capital, weather conditions, including seasonal restrictions, regulatory approvals, oil, natural gas and NGLs prices, costs and drilling results. As a consequence, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Therefore, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

As a result of the uncertainties described above, we may be unable to drill many of our potential resource play drilling locations. In addition, depending on the timing and concentration of the development of the non-proved locations, we would be required to generate or raise significant capital to develop all of our potential drilling locations should we elect to do so. Estimated reserves related to our properties as of December 31, 2015 assumed that capital costs of approximately $109.7 million would be required over a period of approximately five years in order to develop our proved undeveloped reserves. We may not be able to raise or generate the capital required to drill or develop these additional non-proved locations. Any drilling activities we are able to conduct on these potential locations may not be successful or allow us to add additional proved reserves to our overall proved reserves or may result in a downward revision of estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

We have incurred losses from operations for various periods since our inception and may do so in the future.

Our development of and participation in an increasingly larger number of prospects has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this “Risk Factors” section may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves. As a result, we may not be able to sustain profitability or positive cash flows from operating activities in the future.

We cannot be certain that the insurance coverage we maintain will be adequate to cover all losses that may be sustained in connection with our oil and natural gas producing activities.

We maintain an insurance program designed to provide coverage for our property and casualty exposures. Our risk management program provides coverage types, limits and deductibles commensurate with companies of comparable size and with similar risk profiles.

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. As hydraulic fracturing is a key component of our operational strategy, we maintain claims made pollution liability insurance, which provides coverage for long-term gradual seepage pollution events. A loss in connection with our oil and natural gas operations could have a material adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies is inadequate to cover any such loss.

Lower oil, natural gas, and natural gas liquids prices and other factors have resulted, and in the future may result, in ceiling test write-downs.

We use the full cost method of accounting to report our oil and natural gas activities. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural gas properties may not exceed a ceiling limit, which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings.

This is called a ceiling test writedown. Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write-down does not impact cash flows from operating activities, but it does reduce our shareholders' equity.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil, natural gas, and natural gas liquids prices are low. In addition, write-downs may occur if we experience downward adjustments to our estimated proved reserves, or if estimated future development or operating costs increase.

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For example, during 2013, 2014 and 2015 we incurred a ceiling test write-down of zero, $247.7 million and $1.6 billion, respectively.

Additional write-downs may be required in subsequent periods if, among other things, the unweighted arithmetic average of the first-day-of-the-month oil, natural gas, and natural gas liquids prices used in the calculation of the present value of future net revenue from estimated production of estimated proved reserves decline compared to prices used as of December 31, 2015, estimated proved reserve volumes are revised downward, or costs incurred in exploration, development, or acquisition activities exceed the discounted future net cash flows from the additional reserves, if any. For example, the unweighted average of the historical first day of the month pricing for the previous twelve months of oil and natural gas as of December 31, 2015, were $50.28 per Bbl and $2.58 per MMbtu, respectively, compared to $46.26 per Bbl and $2.39 per MMbtu for oil and natural gas, respectively, as of March 2016. Holding all other factors constant, if commodity prices used in our year-end reserve estimates were decreased to these prices as of March 2016, our estimated discounted future cash flows from proved reserves at December 31, 2015 would decrease by approximately $69 million, or 14%.

There are inherent limitations in all internal control over financial reporting systems, and misstatements due to error or fraud may occur and not be detected.

While we have taken actions designed to address compliance with the requirements of the Sarbanes-Oxley Act of 2002, as amended, and the rules and regulations thereunder, there are inherent limitations in our ability to comply with these requirements. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal control over financial reporting and disclosure controls and procedures will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Poor general economic, business or industry conditions, including commodity prices, may adversely affect our ability to refinance our debt, results of operations, liquidity and financial condition.

Oil, natural gas and NGL prices historically and recently have been volatile, and are likely to continue to be volatile in the future, and as such economic uncertainty for the oil and gas industry exists.

Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices and the volatility of oil and gas prices have had a significant effect on the oil and gas industry. If the economic recovery in the United States or abroad slows or is not sustained, demand for petroleum products could diminish or stagnate, which could affect the price at which we can sell our production and affect our vendors', suppliers' and customers' ability to continue operations. Similarly, if the price of oil and gas does not increase, it may affect our production plans and profitability and affect our vendors', suppliers' and customers' ability to continue operations.

Further, our ability to access the capital markets or borrow money may be restricted or more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund operations and capital expenditures in the future or refinance our debt as it becomes current and matures. Economic circumstances, including commodity prices, could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions could have an impact on commodities derivatives transactions if our counterparties are unable to perform their obligations or seek bankruptcy protection. The ultimate outcome and impact of current economic conditions cannot be predicted and may have a material adverse effect on our future results of operations, liquidity and financial condition.

The recent decreases in oil and gas prices have adversely affected our revenues, net income, cash flow and proved reserves. Continued price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. Sustained decreases in oil and gas prices will further adversely affect our revenues, net income, cash flows, proved reserves and our ability to fund capital expenditures.

The results of our horizontal drilling activities are subject to drilling and completion technique risks, and actual drilling results may not meet our expectations for reserves or production. As a result, we may incur material impairment of the carrying value of our unevaluated properties, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

During the year ended December 31, 2015, we completed 37 gross (31.9 net) wells. Risks that we face while horizontally drilling include, but are not limited to, landing our well bore 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 well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our horizontal wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these horizontal drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our horizontal drilling results are less than anticipated, the return on our investment in these areas may not be as attractive as we anticipate. The carrying value of our unevaluated properties could become impaired, which would increase our depletion rate per Mcfe if there were no corresponding additions to recoverable reserves, and the value of our undeveloped acreage could decline in the future.

Our business depends on transportation by truck for our oil and condensate production, and our natural gas production depends on transportation facilities that are owned by third parties.

We transport a significant portion of our oil and condensate production by truck, which is more expensive and less efficient than transportation via pipeline, and can be less reliable than transportation via pipeline in circumstances when availability of trucks is constrained. Our natural gas production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas. The disruption of third-party facilities due to maintenance or weather could negatively affect our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged in such situations. A total shut-in of production could materially affect us due to a lack of cash flows, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local landowners for use in our operations. Over the past several years, areas where we operate have experienced severe drought conditions, and it is possible that such conditions could persist in the future. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce our reserves, which could have an adverse effect on our financial condition, results of operations and cash flows.

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We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce and sell oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax, environmental, occupational, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with such governmental regulations. Matters subject to regulation may include:

- water use, discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- gathering, transportation and marketing of oil and natural gas;
- taxation;
- operations in wilderness, wetlands and other protected areas;
- use, storage, handling and release of hazardous substances; and
- waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws or the enforcement thereof could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

Numerous governmental agencies, such as the EPA, issue regulations to implement and enforce environmental, health and safety laws and regulations, which often require difficult and costly compliance measures. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations, imposition of investigatory or remedial obligations, or subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages, as well as injunctions limiting or prohibiting our activities. Under certain environmental, occupational, health and safety laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages. Some laws and regulations may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions even if they were in compliance with all applicable laws at the time such actions were taken. Under such laws, we could be held liable for environmental contamination at our currently or formerly owned, leased or operated properties as well as third-party locations (such as treatment or disposal facilities). Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. In addition, in some cases private individuals can bring causes of action in court regarding compliance with environmental laws and

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regulations. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations.

In addition, our activities are subject to the regulation by oil and natural gas-producing states relating to conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on or develop our properties. Many factors, including the protection of certain species as well as public opposition, can materially affect the ability to secure construction or operation permits. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. 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 that could have an adverse impact on our ability to develop and produce our reserves. Once operational, enforcement measures can include significant civil penalties for regulatory violations. Under appropriate circumstances, an administrative agency can request a cease and desist order to terminate operations.

Furthermore, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating area.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an essential and common practice in the oil and natural gas industry used to stimulate production of oil and/or natural gas from dense subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the well bore. We routinely apply hydraulic-fracturing techniques in our drilling and completion programs. While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the SDWA involving the use of diesel fuels and published revised permitting guidance in February 2014 addressing the performance of such activities. The EPA has also issued final CAA regulations in 2012 and proposed additional CAA regulations in August 2015 governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; published an advance notice of proposed rulemaking under the Toxic Substances Control Act seeking stakeholder input on development of a requirement regarding disclosure of information on chemical substances and mixtures used in hydraulic fracturing in May 2014 (the public comment period on the EPA's advance notice ended in September 2014, and a final notice of proposed rulemaking is expected in 2016); and proposed in April 2015 effluent limit guidelines that saltwater from shale resource extraction operations must meet before discharging to publicly owned wastewater treatment plants (the final rule is expected to be issued in March 2016). Additionally, in March 2015, the federal Bureau of Land Management published a final rule that establishes new or more stringent standards for hydraulic fracturing on federal and Indian lands, including public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. In addition to rulemakings, increased scrutiny of the oil and natural gas industry may occur as a result of the EPA's FY2014-2016 National Enforcement Initiative, "Ensuring Energy Extraction Activities Comply with Environmental Laws," through which the EPA will 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; starting October 1, 2016, this initiative will continue for three more fiscal years.

In addition, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing, including the disclosure of the chemicals used in the hydraulic fracturing process.

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Certain states, including Texas, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, since 2012, the RRC has required the disclosure of chemical ingredients and water volumes used in the hydraulic fracturing treatment of oil and gas wells. In addition, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Further, in October 2014, the RRC adopted disposal well rule amendments designed to address disposal well operations in areas of historical or future seismic activity. Texas is one of eight states identified in a 2015 U.S. Geological Survey report as having areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater in 2011 and issued a draft assessment for public comment and peer review in June 2015; the assessment is expected to be finalized in 2016. The draft assessment concluded that hydraulic fracturing has not led to widespread, systematic impacts on drinking water resources, but it does have the potential to impact drinking water resources; however, this conclusion has recently been criticized by the EPA's Science Advisory Board. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, 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 federal SDWA or other regulatory mechanisms.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells, increased compliance costs and time, any of which could adversely affect our business.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

The EPA has determined that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted various regulations regarding GHGs under existing provisions of the CAA. For example, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations. Further, the EPA recently finalized a rule that requires reporting of GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The expansion of the EPA's GHG reporting program could result in increased compliance costs. In addition, the EPA has adopted rules regulating the emissions of greenhouse gases from certain sources. The EPA also recently proposed new regulations that set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45% from 2012 levels by 2025; the regulations are expected to be finalized in 2016.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs, with a reduction in the number of allowances over time. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The majority of our operations are located in Texas, making operations vulnerable to risks associated with operating in a limited number of major geographic areas.

Our operations are focused primarily in East Texas and Northern Louisiana, South Texas and North Texas, which means our current producing properties and new drilling opportunities are geographically concentrated in these areas. Because our operations are not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including fluctuations in prices of oil, natural gas and NGLs produced from the wells in these areas, natural disasters, restrictive governmental regulations, transportation capacity constraints, curtailment of production or interruption of transportation, and any resulting delays or interruptions of production from existing or planned new wells.

We rely on independent experts and technical or operational service providers over whom we may have limited control.

We use independent contractors to provide us with technical assistance and services. We rely upon the owners and operators of rigs and drilling equipment, and upon providers of field services, to drill and develop our prospects to production. In addition, we rely upon the services of other third parties to explore or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. Our limited control over the activities and business practices of these providers, any inability on our part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially and adversely affect our business, results of operations and financial condition.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

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

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

Properties that we buy may not produce as projected and we may be unable to determine the reserve potential, identify liabilities associated with the properties or obtain protection from sellers against us.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. However, our reviews of acquired properties are inherently incomplete, because it generally is not feasible to review in detail every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on the higher value properties and will sample the remaining properties for reserve potential. We may also perform only a cursory review of title to these properties at the time we acquire interests in them, particularly if we do not intend to drill on the properties immediately. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties.

Approximately 23% of our core net leasehold acreage was undeveloped as of December 31, 2015, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

As of December 31, 2015, approximately 23% of our core net leasehold acreage was undeveloped, or 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. In addition, substantially all of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Approximately 23% of our total estimated proved reserves at December 31, 2015 were proved undeveloped reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in our reserve engineer report assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our oil and natural gas reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. If we choose not to spend the capital to develop these reserves for any reason, including because we are not able to fund capital expenditures, or if we are not otherwise able to successfully develop these reserves, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC's reserve rules, because proved undeveloped reserves may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any proved undeveloped reserves not developed within this five-year time frame. A removal of such reserves could adversely affect our operations.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of our 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. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut down wells for a lack of a market or because of inadequacy or unavailability of natural gas pipeline, gathering system capacity or processing facilities. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

We are exposed to credit risks of third parties participating in our wells and our customers.

Our principal exposures to credit risk are through joint interest receivables ($7.4 million at December 31, 2015) and the sale of our oil, natural gas and NGLs production ($27.5 million in receivables at December 31, 2015), which we market to energy marketing companies and refineries. 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 leases on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our oil, natural gas and NGLs receivables with several significant customers.

These transactions expose us to credit risk in the event of default of our counterparty. We do not require most of 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. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

We depend on a limited number of key personnel who would be difficult to replace. The volatility in commodity prices and business performance may affect our ability to retain senior management and the loss of these key employees may affect our business, financial condition and results of operations.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy. The volatility in commodity prices and business performance may affect our ability to retain senior management or key employees. The loss of the services of key management personnel could have a material adverse effect on our business, financial condition and results of operations. Additionally, if we are unable to find, hire and retain needed key personnel in the future, our business, financial condition and results of operations could be materially and adversely affected. Further, we do not maintain "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and 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 oil and 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. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other 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 in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A portion of our business activities is conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells that we do not operate, we may not be in a position to remove the operator in the event of poor performance.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

We derive a significant portion of our revenues from a few customers. For the year ended December 31, 2015, three customers accounted for approximately 52% of our total revenues. If these customers fail to timely pay for our production or they cease purchasing our production and we are unable to secure alternative purchasers for our production on a timely basis, our financial condition and results of operations would be materially adversely affected.

Full cost accounting rules have required us to record a non-cash asset write-down for the year ended December 31, 2015, and we may be required to record similar non-cash asset write-downs in the future.

We utilize the full cost method of accounting for natural gas and oil exploration and development activities. Under full cost accounting, we are required to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or “ceiling,” of the book value of natural gas and oil properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted average of the first day of the month natural gas and oil prices for the prior twelve months. If the net book value of natural gas and oil properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, accounting rules require us to impair or “write down” the book value of our natural gas and oil properties. Once incurred, a write-down of natural gas and oil properties is not reversible at a later date.

Costs associated with unevaluated properties are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and the ceiling test limitation. Accordingly, a significant change in these factors, some of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to amortization and the ceiling test limitation.

As of December 31, 2015, the unweighted average of the first day of the month natural gas and oil prices for the prior twelve months was $50.28 per Bbl of oil and $2.58 per MMbtu for natural gas, which resulted in a non-cash impairment charge for oil and gas properties of $1.6 billion for the year ended December 31, 2015.

There is risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. Natural gas prices declined significantly in late 2014 and throughout 2015 to the lowest level in recent years and continue to trade near historic lows. If the average of the unweighted first day of the month natural gas or oil prices for the prior twelve month periods remains at current levels or decline, we could have a further reduction in our asset carrying value for oil and gas properties.

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

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us that participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require certain counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The final rules will be phased in over time according to a specified schedule which is dependent on the finalization of certain other rules to be promulgated jointly by the CFTC and the SEC. The Dodd-Frank Act and any new regulations could increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts,

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reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. In the future, if we are unable to use derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas liquids and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas liquids and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is even lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Our business and financial results may be adversely affected if proposed tax reforms are enacted or similar initiatives are implemented as part of the U.S. government’s efforts to reduce budget deficits.

The Obama administration’s budget proposals for fiscal year 2016 contain numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently available to U.S. oil and natural gas companies. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling and development costs in the year incurred; repeal of the percentage depletion deduction for oil and natural gas properties; repeal of the domestic manufacturing tax deduction for oil and natural gas companies; and increase in the geological and geophysical amortization period for independent producers. Several bills have been introduced in Congress that would implement these proposals. It is unclear whether any of these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of legislation containing some or all of these provisions or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could have a material adverse effect on our business, financial condition and results of operations.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our products and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely affected if infrastructure integral to our customers’ operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our operations are subject to the risk of cyber-attacks that could have a material adverse effect on our results of operations and financial condition.

Our information technology systems are subject to possible breaches and other threats that could cause us harm. If our systems for protecting against cyber security risks prove not to be sufficient, we could be adversely affected by the loss or damage of intellectual property, proprietary information, or client data, interruption of business operations, or additional costs to prevent, respond to, or mitigate cyber security attacks. These risks could have a material adverse effect on our business, results of operations, and financial condition.

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Item 1B.Unresolved Staff Comments

There were no unresolved SEC staff comments at December 31, 2015.

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Item 3.Legal Proceedings

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but our management team does not expect the outcome of pending or threatened legal matters to have a material adverse impact on our financial condition.

The Parish of Jefferson v. Destin Operating Company, Inc., et al.

On November 11, 2013, Jefferson Parish filed suit against the Company and fourteen (14) other defendants, alleging that certain of defendants' oil and gas exploration, production, and transportation operations associated with the development of the Bay de Chene, Queen Bess Island, and Saturday Island oil and gas fields in Jefferson Parish, Louisiana were conducted in violation of Louisiana's State and Local Coastal Resources Management Act and its associated rules and regulations, and that these activities caused substantial damage to land and waterbodies located in the Jefferson Parish Coastal Zone. The Company tendered a claim for indemnity to Texas Petroleum Investment Company ("TPIC"), which TPIC rejected. The Company responded with a reservation of rights to indemnity from TPIC. The case was removed to federal court and is currently pending in the United States District Court for the Eastern District of Louisiana. The case was administratively closed pending the court's decision regarding federal jurisdiction in other similar lawsuits. Those lawsuits were recently remanded to Louisiana state court. On March 12, 2015, the case was administratively reopened and the court directed the defendants to show cause as to how and why the jurisdictional issues in this case differ from those issues presented in the similar lawsuits. Defendants filed the requisite briefing and the matter is under advisement. Plaintiffs seek unspecified monetary damages and restoration of the Jefferson Parish Coastal Zone to its original condition. On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. Plaintiffs filed a motion to dismiss the Company from the litigation on July 21, 2015.

The Parish of Plaquemines v. ConocoPhillips Company, et al.

On November 8, 2013, Plaquemines Parish filed suit against the Company and seventeen (17) other defendants, alleging that certain of defendants' oil and gas exploration, production, and transportation operations associated with the development of the Bay Batiste, Grand Ecaille, Lake Washington, Manila Village, Manila Village Southeast, Saturday Island, and Saturday Island Southeast oil and gas fields in Plaquemines Parish, Louisiana were conducted in violation of Louisiana's State and Local Coastal Resources Management Act and its associated rules and regulations, and that these activities caused substantial damage to land and waterbodies in the Plaquemines Parish Coastal Zone. Forest tendered a claim for indemnity to Texas Petroleum Investment Company ("TPIC"), which TPIC rejected. The Company responded with a reservation of rights to indemnity from TPIC. The case was removed to the United States District Court for the Eastern District of Louisiana, but was remanded to Louisiana state court on March 10, 2015. The matter is now pending before the 25th Judicial District Court for the Parish of Plaquemines, State of Louisiana. Plaintiffs seek unspecified monetary damages and restoration of the Plaquemines Parish Coastal Zone to its original condition. On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. The Company was dismissed from the litigation on July 28, 2015.

Forest Oil Corporation v. El Rucio Land and Cattle Company, Inc., et al.

On February 29, 2012, two members of a three-member arbitration panel reached a decision adverse to the Company in the proceeding styled Forest Oil Corp. et al. v. El Rucio Land & Cattle Co. et al. The third member of the arbitration panel dissented. The proceeding was initiated in January 2005 and involves claims asserted by the landowner-claimant based on the diminution in value of its land and related damages allegedly resulting from operational and reclamation practices employed by Forest Oil in the 1970s, 1980s, and early 1990s. The arbitration decision awarded the claimant $23 million in damages and attorneys' fees and additional injunctive relief regarding future surface-use issues. On October 9, 2012, after vacating a portion of the decision imposing a future bonding requirement on the Company, the trial court for the 55th Judicial District of Harris County, Texas, reduced the arbitration decision to a judgment. The judgment was affirmed by the Court of Appeals for the First District of Texas on July 24, 2014, and a motion for rehearing was denied on August 8, 2014. The Company filed a petition for review with the Texas Supreme Court on January 5, 2015, and on May 1, 2015, the Texas Supreme Court requested full briefing on the merits. On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. On September 15, 2015, the bankruptcy court granted an unopposed motion to lift the automatic stay thereby allowing the appeal currently pending in the Texas Supreme Court to move forward. All briefing in the matter is now completed.

Stourbridge Investments, LLC v. Forest Oil Corporation, et al., Raul v. Carroll, et al., Rothenberg v. Forest Oil Corporation, et al., Gawlikowski v. Forest Oil Corporation, et al., Edwards v. Carroll, et al., Jabri v. Forest Oil Corporation, et al., Olinatz v. Forest Oil Corporation, et al.

Following the May 6, 2014 announcement of the proposed Combination, six putative class action lawsuits were filed by Forest Oil shareholder in the Supreme Court of the State of New York, County of New York, alleging breaches of fiduciary duty by the directors of Forest Oil and aiding and abetting of those breaches of fiduciary duty by Sabine entities in connection with the proposed Combination. By order dated July 8, 2014, the six New York cases were consolidated for all purposes under the caption In re Forest Oil Corporation Shareholder Litigation, Index No. 651418/2014. On July 17, 2014, plaintiffs in the consolidated New York action filed a Consolidated Class Action Complaint (the "Consolidated Complaint"). The Consolidated Complaint seeks to certify a plaintiff class consisting of all holders of Forest Oil common stock other than the defendants and their affiliates. The defendants named in these actions include the directors of Forest Oil (Patrick R. McDonald, James H. Lee, Dod A. Fraser, James D. Lightner, Loren K. Carroll, Richard J. Carty, and Raymond I. Wilcox), as well as Sabine and certain of its affiliates (specifically, Sabine Oil & Gas LLC, Sabine Investor Holdings LLC, Sabine Oil & Gas Holdings LLC, and Sabine Oil & Gas Holdings II LLC). The Consolidated Complaint also purports to identify FR XI Onshore AIV, L.L.C. as a defendant, but no causes of action are alleged against that entity.

The Consolidated Complaint alleges that the proposed Combination arises out of a series of unlawful actions by the board of directors of Forest Oil seeking to ensure that Sabine and affiliates of First Reserve Corporation ("First Reserve") acquire the assets of, and take control over, Forest Oil through an alleged "three-step merger transaction" that allegedly does not represent a value-maximizing transaction for the shareholders of Forest Oil. The Consolidated Complaint also complains that the proposed Combination has been improperly restructured to require only a majority vote of current Forest Oil shareholders to approve the Combination with Sabine, rather than a two-thirds majority as would have been required under the original transaction structure. The Consolidated Complaint additionally alleges that members of Forest Oil's board, as well as Forest Oil's financial adviser for the proposed Combination, are subject to conflicts of interest that compromise their loyalty to Forest Oil's shareholders, that the defendants have improperly sought to "lock up" the proposed Combination with certain inappropriate "deal protection devices" that impede Forest Oil from pursuing superior potential transactions with other bidders.

The Consolidated Complaint asserts causes of action against the directors of Forest Oil for breaches of fiduciary duty and violations of the New York Business Corporation Law, as well as a cause of action against the Sabine defendants for aiding and abetting the directors' breaches of duty and violations of law, and it seeks preliminary and permanent injunctive relief to enjoin consummation of the proposed Combination or, in the alternative, rescission and/or rescissory and other damages in the event that the proposed Combination is consummated before the lawsuit is resolved.

In addition to these New York proceedings, one putative class action lawsuit has been filed by Forest Oil shareholders in the United States District Court for the District of Colorado. That action, captioned Olinatz v. Forest Oil Corp., No. 1:14-cv-01409-MSK-CBS, was commenced on May 19, 2014, and plaintiffs filed an Amended Complaint (the "Olinatz Complaint") on June 13, 2014. The Olinatz Complaint also alleges breaches of fiduciary duty by the directors of Forest Oil and aiding and abetting of those breaches of fiduciary duty by the Sabine defendants in connection with the proposed Combination, as well as related claims alleging violations of Section 14 (a) and 20 (a) of the Securities Exchange Act of 1934, and Securities and Exchange Commission Rule 14a-9 promulgated thereunder, in connection with alleged misstatements in a Form S-4 Registration Statement filed by Forest Oil on May 29, 2014, which recommends that Forest Oil shareholders approve the proposed Combination. The Olinatz Complaint names as defendants Forest Oil and certain of its affiliates (specifically, Forest Oil Corporation, New Forest Oil Inc., and Forest Oil Merger Sub Inc.), the directors of Forest Oil (Patrick R. McDonald, James H. Lee, Dod A. Fraser, James D. Lightner, Loren K. Carroll, Richard J. Carty, and Raymond I. Wilcox), and Sabine and certain of its affiliates (specifically, Sabine Oil & Gas LLC, Sabine Investor Holdings LLC, Sabine Oil & Gas Holdings LLC, and Sabine Oil & Gas Holdings II LLC), and seeks preliminary and permanent injunctive relief to enjoin consummation of the Combination or, in the alternative, rescission in the event the proposed Combination is consummated before the lawsuit is resolved, as well as imposition of a constructive trust on any alleged benefits improperly received by defendants.

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On October 14, 2014, on motion by the Colorado plaintiffs, the Court in the Colorado action entered an order directing the Clerk of the Court to administratively close the action, subject to reopening on good cause shown.

On November 11, 2014, the defendants reached an agreement in principle with plaintiffs in the New York action regarding a settlement of that action, and that agreement is reflected in a memorandum of understanding executed by the parties on that date. The settlement, if consummated, would also resolve the Colorado action. In connection with the settlement contemplated by the memorandum of understanding, Forest Oil agreed to make certain additional disclosures related to the proposed transaction with Sabine, which are contained in Forest Oil's November 12, 2014 Form 8-K, and Sabine agreed that, within 120 days after the closing of the proposed combination transaction, Sabine Investor Holdings LLC will designate for a period of no less than three (3) years at least one additional independent director, as defined in Section 303A.02 of the New York Stock Exchange Listed Company Manual, as a Sabine Nominee (as defined in Section 1.4 of the Amended and Restated Agreement and Plan of Merger). The total number of Sabine Nominees will remain unchanged, but at least one of the remaining two Sabine Nominees that had not yet been determined was required to be independent. In connection with the closing of the Combination, Thomas Chewning, an independent director as defined in Section 303A.02 of the New York Exchange Listed Company Manual, was appointed as a Sabine Nominee. The memorandum of understanding contemplates that the parties will enter into a stipulation of settlement.

On March 13, 2015, plaintiffs informed Sabine that they believed Sabine had materially violated the terms of the memorandum of understanding by (i) failing to replace or create a mechanism to replace an independent director who resigned from the board of directors in January of 2015, and (ii) making changes to the terms of the merger agreement that were not necessary or required to facilitate the consummation of the proposed transaction without first disclosing and permitting shareholders to vote on the changes. Sabine disagrees with plaintiffs' position and believes it has fully complied with the memorandum of understanding. In an attempt to facilitate a resolution, however, Sabine offered to: (i) appoint an independent director if an additional director was added to the Board of Directors (bringing the total number of directors to eight) in the next twelve months, and (ii) remove or waive the "Reincorporation Penalty" provision. Plaintiffs accepted the offer on April 22, 2015, contingent upon the Parties' reaching agreement on a stipulation of settlement, which they are presently negotiating.

The stipulation of settlement will be subject to customary conditions, including court approval. In the event the parties enter into a stipulation of settlement, a hearing will be scheduled at which the New York Court will consider the fairness, reasonableness, and adequacy of the settlement. If the settlement is finally approved by the court, it will resolve and release all claims or actions that were or could have been brought challenging any aspect of the proposed combination transaction, the Amended and Restated Agreement and Plan of Merger, the merger agreement originally entered into by Sabine Investor Holdings LLC, Forest Oil, New Forest Oil Inc. and certain of their affiliated entities on May 5, 2014, any disclosure made in connection therewith, including the Definitive Proxy Statement, and all other matters that were the subject of the complaint in the New York action, pursuant to terms that will be disclosed to shareholders prior to final approval of the settlement. In addition, in connection with the settlement, the parties contemplate that the parties will negotiate in good faith regarding the amount of attorney's fees and expenses that shall be paid to plaintiffs' counsel in connection with the Actions. There can be no assurances that the parties will ultimately enter into a stipulation of settlement or that the New York Court will approve the settlement even if the parties were to enter into such stipulation. In such event, the proposed settlement as contemplated by the memorandum of understanding may be terminated. The parties are presently negotiating the stipulation of settlement. At this time, the Company is unable to guarantee the potential outcome of this litigation or the ultimate exposure.

On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As a result of the pending bankruptcy, this matter is currently stayed.

HPIP-Gonzales Holdings, LLC v. Forest Oil Corporation

On November 11, 2014, HPIP-Gonzales Holdings, LLC (“HPIP”) initiated arbitration against the Company alleging that the Company breached various provisions, along with our duty of good faith and fair dealing, of the Gathering, Treating and Processing Agreement with HPIP entered into in May 2013 and the Acid Gas Handling Agreement with HPIP entered into in May 2014 (collectively, the “HPIP Agreements”). HPIP also sought to exercise a contractual provision requiring us to purchase the facilities governed by the HPIP Agreements in the event the related drilling program terminates. On December 19, 2014, the Company filed its Answering Statement and Notice of Counterclaim,

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denying HPIP's claims and asserting generally that HPIP breached various provisions of the agreements, resulting in damages to the Company. The Company further alleged that its drilling program had not terminated. On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As a result of the pending bankruptcy, the arbitration is currently stayed.

Wilmington Savings Fund Society, FSB v. Forest Oil Corporation

On February 26, 2015, the Company was served with a complaint concerning the indenture governing its 2019 Notes. The complaint is pending in the Supreme Court of the State of New York and generally alleges that certain events of default occurred with respect to the 2019 Notes due to the business combination between Forest Oil Corporation and Sabine Oil & Gas LLC. The Company also received a notice of default and acceleration from the trustee with respect to the 2019 Notes containing similar allegations. If the Company is not successful in its defense of this complaint, the Company may be required to redeem the holders of the 2019 Notes at 101% of the outstanding principal, plus accrued and outstanding interest of the notes. The Company filed its Answer to the complaint on April 17, 2015. The Company believes the allegations against it are without merit and intend to vigorously defend against such claims and pursue any and all defenses available. However, the Company is unable to predict the outcome of such matter, and the proceedings may have a negative impact on the Company's liquidity, financial condition and results of operations.

The Company is separately evaluating potential claims that it may assert against the trustee for the 2019 Notes for any and all losses the Company may suffer as a result of the complaint or notice. The Company can provide no guarantee that any such claims, if brought by the Company, will be successful or, if successful, that the responsible parties will have the financial resources to address any such claims. While the Company intends to vigorously defend the claims against it and believe they are without merit, an adverse ruling could cause the Company's indebtedness to become immediately due and payable.

Additional claims, lawsuits, or proceedings may be filed or commenced arising out of the indentures to which the Company is a party and with respect to the business combination.

On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As a result of the pending bankruptcy, this matter is currently stayed.

Patrick R. McDonald v. Sabine Oil & Gas Corporation

On March 30, 2015, Mr. Patrick R. McDonald filed a complaint against the Company in the District Court, City and County of Denver, State of Colorado, alleging that the Company breached its obligations under a severance agreement with Mr. McDonald, and violated the Colorado Wage Act by allegedly not paying Mr. McDonald certain accrued vacation. The complaint arises from the Company's decision to defer the payment of severance and associated benefits to certain of its former executive officers. In the complaint, Mr. McDonald seeks relief in the form of monetary damages. Mr. McDonald served as an executive officer until December 2014, and continues to serve on the Company's Board of Directors. On April 29, 2015, the Company removed the lawsuit from state court to the U.S. District Court for the District of Colorado, where it now pends. The Company filed an answer to Mr. McDonald's complaint on May 6, 2015. On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As a result of the pending bankruptcy, this matter is currently stayed.

Sabine Oil & Gas Corporation v. Wilmington Trust, N.A.

On July 15, 2015, the Company filed an adversary proceeding asserting, on its behalf, a constructive fraudulent transfer claim against the Term Loan Facility administrative agent Wilmington Trust, N.A. Specifically, the complaint states that immediately before the Combination between Sabine Oil & Gas LLC and Forest Oil

Corporation, both Forest Oil Corporation and Sabine Oil & Gas LLC were insolvent from a balance-sheet standpoint. The complaint likewise alleges that immediately after the Business Combination, the combined company was insolvent. The complaint also alleges that Forest Oil Corporation and its creditors did not receive reasonably equivalent value in the Combination and financing transactions that occurred simultaneously on December 16, 2014. Specifically, the complaint alleges that Forest Oil Corporation's creditors did not receive reasonably equivalent value in exchange for pledging hundreds of millions of dollars of previously unencumbered oil and gas assets to secure the Term Loan Facility debt that was under-

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secured, and that Sabine Oil & Gas LLC had previously incurred. Accordingly, pursuant to Bankruptcy Code Section 551, the Company is seeking to avoid and preserve, for the benefit of our unsecured creditors, the liens imposed on legacy Forest Oil Corporation assets that were pledged to secure the preexisting Sabine Oil & Gas LLC's Term Loan Facility. In August 2015, the defendant filed a motion to dismiss, which is now fully briefed. The court heard first oral argument on October 15, 2015, but did not rule.

On December 30, 2015, the official committee for unsecured creditors (the "Creditors Committee") and counsel for the Forest Notes Trustees filed motions to intervene in the adversary proceeding. On January 5, 2016, the Creditors Committee also filed an objection to Wilmington Trust, N.A.'s motion to dismiss the complaint. The court held a second hearing on the motion to dismiss on January 12, 2016, but has yet to rule.

Item 4.Mine Safety Disclosures

Not applicable.

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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, our common stock, par value $0.10 per share ("Common Stock"). Our Common Stock is traded on the OTC Pink Marketplace under the symbol "SOGC." On March 21, 2016, there were 211,693,364 shares of our Common Stock outstanding held by 695 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

Under our Amended and Restated Certificate of Incorporation, we are authorized to issue up to 650,000,000 shares of our Common Stock, and up to 10,000,000 shares of our Preferred Stock. On March 21, 2016, there were 2,508,945 shares of our Series A preferred shares outstanding.

For periods prior to the Combination on December 16, 2014, when we were listed on the NYSE under the symbol "FST," the table below reflects the high and low intraday sales prices per share of the Common Stock as reported by the NYSE. For periods following our delisting on the NYSE, we commenced trading on the OTCQB under the symbol "SOGC." Beginning on December 17, 2014, the table below reflects the high and low intraday sales price per share of the Common Stock as reported by the OTCQB. As a result of the Bankruptcy Petitions, the Company's common stock can no longer be traded on the OTCQB and is now trading on the OTC Pink Marketplace. Beginning on July 16, 2015, the table below reflects the high and low intraday sales price per share of the Common Stock as reported by the OTC Pink Marketplace. There were no cash dividends declared on the Common Stock in 2013, 2014 or 2015. On March 21, 2016, the closing price of our Common Stock was $0.01. Our Common Stock's trading range during the periods indicated was as follows:

	Common Stock	
	High	Low
2014		
First Quarter	$ 3.73	$ 1.68
Second Quarter	2.59	1.75
Third Quarter	2.43	1.16
Fourth Quarter	1.31	0.16
2015		
First Quarter	$ 0.33	$ 0.04
Second Quarter	0.11	0.06
Third Quarter	0.07	0.01
Fourth Quarter	0.03	0.00

Dividend Restrictions

Our ability to pay dividends and make certain payments was subject to the restrictions included in the covenants of our debt obligations. However, with the filing of the Bankruptcy Petitions and until our emergence from bankruptcy, our ability to make such payments is limited and now subject to the approval of the Bankruptcy Court. On September

30, 2011, Forest distributed a special stock dividend in connection with the spin-off of Lone Pine Resources, Inc.; however, prior to the Combination, Forest had not paid cash dividends on its Common Stock during the previous five years. The future payment of cash dividends, if any, on the Common Stock is within the discretion of the Board of Directors and will depend on our earnings, capital requirements, financial condition, and other relevant factors. We do not currently intend to pay any cash dividends in the foreseeable future, and there is no assurance that we will pay any cash dividends. For further information regarding our equity securities and our ability to pay dividends on our Common Stock, please see “Note 8. Long-Term Debt” and “Note 9. Shareholders’ Equity” to our Consolidated Financial Statements included herein.

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Unregistered Sales of Equity Securities

On December 16, 2014, in connection with the closing of the Combination, we issued an aggregate of 79,241,916 common shares and 2,508,945 Series A preferred shares (convertible into 250,894,494 common shares) to Sabine Investor Holdings and FR XI Onshore AIV, LLC, a Delaware limited liability company ("AIV Holdings"). The issuance of the common shares and Series A preferred shares was made in reliance upon an exemption from registration provided by Section 4(a)-(2) of the Securities Act as a transaction not involving a public offering. We did not make any sales of unregistered equity securities during the year ended December 31, 2015. As a result of the filing of the Bankruptcy Petitions, there is a high probability that the Series A preferred shares (and the common shares that the preferred can convert into) will receive no recovery and be cancelled.

Issuer Purchases of Equity Securities

We did not purchase any of our equity securities during 2015.

Securities Authorized for Issuance under Equity Compensation Plans

In November 2014, we adopted the 2014 Long Term Incentive Plan (the "2014 LTIP") under which nonstatutory options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, and other stock-based awards may be granted to our employees, directors and consultants. The aggregate number of shares of common stock that the Company may issue under the 2014 LTIP may not exceed 20 million shares. The following table summarizes the restricted stock activity in the 2014 LTIP for the year ended December 31, 2015.

	Restricted Stock Awards Weighted		
	Number of Shares	Weighted Average Grant Date Fair Value ($)	Number of Shares Remaining Available for Future Issuance under 2014 LTIP
Unvested at December 31, 2014	13,923,230	$ 0.34	3,205,597
Awarded	719,132	0.24	(719,132)
Vested	(2,727,871)	0.34	—
Forfeited	(1,815,200)	0.34	1,815,200
Unvested at December 31, 2015	10,099,291	0.33	4,301,665

Incentive Units

The Incentive Units were issued pursuant to the Combination in exchange for Incentive Units that were outstanding prior to the Combination, and were amended in connection with the closing of the Combination. The Incentive Units that were outstanding prior to the Combination were not a substantive class of equity and participated only upon liquidation events meeting certain requisite financial thresholds which were not considered probable, and, as such, were considered to be liability-based awards with no fair value recognized as of December 31, 2013. As amended, the Incentive Units represent the equivalent of stock appreciation rights redeemable for an applicable number of common shares of the Company (based on the value of the common shares). As such, the Incentive Units as amended in connection with the Combination were considered to be equity-based awards with a grant date fair value of approximately $2.1 million, of which compensation expense will be recognized on a straight line basis over the requisite service period. The compensation expense recognized in the year ended December 31, 2015 was $0.4 million. On December 16, 2014, in connection with the closing of the Combination, subject to the approval of the Sabine shareholders, the board of directors of Sabine voted to amend the 2014 LTIP to increase the total number of Common Shares reserved for issuance in connection with awards under the 2014 LTIP from 20 million to 40 million, effective as of the date of such shareholder approval.

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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 on Form 10-K. 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 expectations include changes in oil and natural gas 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 on Form 10-K, 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.”

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties onshore in the United States. Our properties are primarily focused in three core geographic areas:

· East Texas targeting the Cotton Valley Sand, and Haynesville Shale formations;
· South Texas, targeting the Eagle Ford Shale formation; and
· North Texas, targeting the Granite Wash formation.

As of December 31, 2015, we held interests in approximately 272,100 gross (217,000 net) acres in East Texas, 82,900 gross (53,400 net) acres in South Texas and 33,900 gross (25,300 net) acres in North Texas. As of December 31, 2015, we were the operator on 90%, 99% and 99% of our net acreage positions in East Texas, South Texas and North Texas, respectively.

Our 2016 capital expenditures are forecasted to total approximately $18 million. As a result, we expect production growth from our 2016 capital program will not offset production declines, which will result in material decreases to our production and related cash flows. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget based on liquidity, commodity prices and drilling results.

Our MD&A includes the following sections;

· Chapter 11 Filings - a description of our recent events and our Chapter 11 filings
· The Combination - a description of the 2014 combination with Forest Oil Corporation
· Sources of Revenue
· Principal Components of Cost Structure
· Significant Transactions
· Results of Operations - an analysis of our consolidated results of operations for the annual periods presented in our financial statements
· Liquidity, Capital Resources and Financial Position - an analysis of our cash flows, sources and uses of cash, contractual obligations and commercial commitments

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Chapter 11 Filings

On July 15, 2015, we and certain of our subsidiaries, including Giant Gas Gathering LLC, Sabine Bear Paw Basin LLC, Sabine East Texas Basin LLC, Sabine Mid-Continent Gathering LLC, Sabine Mid-Continent LLC, Sabine Oil & Gas Finance Corp., Sabine South Texas Gathering LLC, Sabine South Texas LLC and Sabine Williston Basin LLC (collectively, the “Filing Subsidiaries” and, together with us, the “Debtors”), filed voluntary petitions (the “Bankruptcy Petitions”) for reorganization under the Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York (the “Bankruptcy Court”). The Debtors Chapter 11 cases (the “Chapter 11 Cases”) are being jointly administered under the case styled In re Sabine Oil & Gas Corporation, et al, Case No. 15-11835. The Debtors will continue to operate their businesses as “debtors-in-possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

By certain “first day” motions filed in the Chapter 11 Cases, we obtained Bankruptcy Court approval to, among other things and subject to the terms of the orders entered by the Bankruptcy Court, pay certain employee wages, health benefits and certain other employee obligations, pay certain lienholders and forward funds to third parties, including royalty holders and other partners.

For the duration of our Chapter 11 proceedings, our operations and ability to develop and execute our business plan are subject to the risks and uncertainties associated with the Chapter 11 process. For example, negative events associated with our Chapter 11 proceedings could adversely affect our relationships with our suppliers, service providers, customers, and other third parties and our ability to retain employees, which in turn could adversely affect our operations and financial condition. For a description of these and other risks, please see “Part I, Item 1A. Risk Factors.” As a result of these risks and uncertainties, the number of our outstanding shares and shareholders, assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 proceedings, and the description of our operations, properties and capital plans included in this Annual Report may not accurately reflect our operations, properties and capital plans following the Chapter 11 process.

In particular, subject to certain exceptions, under the Bankruptcy Code, the Debtors may assume, assign, or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and certain other conditions. The rejection of an executory contract or unexpired lease is generally treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Debtors of performing their future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Counterparties to such rejected contracts or leases may assert claims against the applicable debtor’s estate for such damages. The assumption of an executory contract or unexpired lease generally requires the Debtors to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with the Debtors in this Annual Report, including where applicable a quantification of our obligations under any such executory contract or unexpired lease with the Debtors, is qualified by any overriding rejection rights we have under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and the Debtors expressly preserve all of their rights with respect thereto.

Our filing of the Bankruptcy Petitions described above constitutes an event of default that accelerated our obligations under the New Revolving Credit Facility, the Term Loan Facility, the 2017 Notes and the Legacy Forest Notes. We have classified all debt as “Liabilities Subject to Compromise” in the Consolidated Balance Sheet at December 31, 2015. This debt includes unsecured and under secured obligations which are reported at the amounts expected to be allowed as claims by the Bankruptcy Court, even if they may be settled for lesser amounts. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and the reported income and expenses could be required and could be material. For additional description of the defaults present under our debt obligations, please see Note 8 within “Part II, Item 8. Financial Statements and Supplementary Data”.

We are making adequate protection payments to the lenders under the New Revolving Credit Facility in an amount equal to the non-default rate of interest, fees and costs due and payable on a monthly basis under the New Revolving Credit Facility, in accordance with the cash collateral order filed with the Bankruptcy Court. Additionally, cash generated by the Company deemed to be proceeds of the oil and gas properties that represent prepetition collateral is

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deposited into a segregated account, which is reflected as Cash in the Consolidated Balance Sheet as of December 31, 2015, and is used solely to pay for the operations of the prepetition collateral properties.

On October 21, 2015 the Debtors filed a motion to set a bar date to assist with the claims reconciliation process. On January 26, 2016, the Debtors filed with the Bankruptcy Court a joint plan of reorganization (the "Plan of Reorganization") for the resolution of the outstanding claims against and interests in the Debtors and a disclosure statement (the "Disclosure Statement") related thereto. The Plan of Reorganization, if implemented as proposed by the Debtors, would significantly reduce our outstanding long-term debt and annual interest payments. The Disclosure Statement has not yet been approved by the Bankruptcy Court. Although the Debtors currently have the exclusive right to file a plan and solicit the appropriate votes thereon, such rights expire on February 10, 2016 and April 11, 2016, respectively. Accordingly, the Debtors have filed a motion to further extend their exclusive right to file and solicit acceptance of the Plan of Reorganization, or any other plan, through June 9, 2016 and August 9, 2016, respectively. A hearing on that motion will be held before the US Bankruptcy Court on April 7, 2016 and April 11, 2016. There can be no assurances regarding our ability to successfully develop, confirm or consummate the Plan of Reorganization, an alternative plan or reorganization or another alternative restructuring transactions, including a sale of all or substantially all of our assets, which satisfies the conditions of the Bankruptcy Code and is authorized by the Bankruptcy Court.

The Combination

On December 16, 2014, the Legacy Sabine Investors contributed the equity interests in Sabine O&G to Sabine Oil & Gas Corporation, which was then known as Forest Oil Corporation. In exchange for this contribution, the Legacy Sabine Investors received shares of Sabine common stock and Sabine Series A preferred stock, collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine. Immediately following the contribution, Sabine O&G and related holding companies merged into Forest, with Forest surviving the mergers. Holders of Sabine common stock immediately prior to the closing of the Combination continued to hold their Sabine common stock following the closing, which immediately following the closing represented approximately a 26.5% economic interest in Sabine and 60% of the total voting power in Sabine. On December 19, 2014, Forest Oil Corporation changed its name to Sabine Oil & Gas Corporation. In connection with the completion of the Combination, the executive management team of Sabine O&G was appointed as the executive management team of Sabine, and the members of the former executive management team of Forest resigned or were removed from their positions.

Sabine O&G is considered the predecessor of Sabine or acquirer of Forest, and, accordingly, the historical financial statements and results of operations of Sabine for periods prior to the completion of the Combination are those of Sabine O&G, as the predecessor, and the historical financial statements and results of operations for the year ending December 31, 2014 include the historical financial statements of Sabine O&G, with the combined operating results of Forest consolidated therein only from the closing date of December 16, 2014 and thereafter. Accordingly, our results of operations discussed in this section may not be indicative of our results of operation following the Combination. The underlying Forest assets acquired and liabilities assumed by us were based on their respective fair market values. No goodwill resulted from the Combination as the fair value of assets acquired and liabilities assumed approximated purchase price.

Prior to the Combination, Sabine O&G was a privately-held company and Forest's common stock was listed on the NYSE. Currently, the Company's common stock trades on the OTC Pink Marketplace under the ticker symbol "SOGC".

Source of Revenues

We derive substantially all of our revenue from the sale of oil, NGLs and natural gas that are produced from our interests in properties located onshore in the United States. Oil and natural gas prices are inherently volatile and are influenced by many factors outside of our control. Oil and natural gas prices decreased significantly in the second half of 2014 and have remained low through the first quarter of 2016. If commodity prices remain at current levels, we expect significantly lower revenues and operating cash flows compared to historical results.

In the past we have used derivative instruments to hedge future sales prices on a significant portion of oil and natural gas production, to achieve more predictable cash flows and to reduce exposure to downward price fluctuations. However, as a result of certain events of default under our derivative contracts, all our derivative instruments have been

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terminated and we no longer have any derivative contracts in place. See "Commodity Hedging Activities" below for more information regarding our economic hedge positions.

Principal Components of Cost Structure

- Lease operating, marketing, gathering, transportation and other. These are costs incurred to produce oil and natural gas and deliver the volumes to the market, together with the costs incurred to maintain producing properties, such as maintenance and repairs. These costs, which have both a fixed and variable component, are primarily a function of volume of oil and natural gas produced from currently producing wells and incrementally from new production from drilling and completion activities. Lease operating expenses include workover expenses.
- Production and ad valorem taxes. Production taxes are paid on produced oil and natural gas primarily based on the wellhead value of production. The applicable rates vary across the areas in which we operate. As the proportion of production changes from area to area, production tax rates will vary depending on the quantities produced from each area and the applicable production tax rates then in effect. Ad valorem taxes are typically computed on the basis of a property valuation as determined by certain state and local taxing authorities and will vary annually based on commodity price fluctuations.
- General and administrative. This cost includes all overhead associated with our business activities, including payroll and benefits for corporate staff, costs of maintaining our headquarters, audit, tax, legal and other professional and consulting fees, insurance and other costs necessary in the management of our production and development operations.

As a full cost method of accounting company, we capitalize general and administrative expenses that are directly attributable to our oil and natural gas activities. We capitalized \$9.2 million, \$10.1 million and \$6.6 million for the years ended December 31, 2015, 2014 and 2013, respectively.

- Depletion, depreciation and amortization ("DD&A"). This includes the systematic expensing of the capitalized costs incurred to acquire and develop oil and natural gas properties. As a full cost company, we capitalize all costs associated with acquisition, exploration, development and related efforts and deplete these costs using the units-of-production method.
- Impairments. We evaluate the impairment of proved oil and natural gas properties on a full cost basis. Property impairment charges result from application of the ceiling test under the full cost accounting rules, which we are required to calculate on a quarterly basis. The ceiling test requires that a non-cash impairment charge be taken to reduce the carrying value of oil and natural gas properties if the carrying value exceeds a defined cost-center ceiling. Because current commodity prices, and related calculations of the discounted present value of reserves, are significant factors in the full cost ceiling test, impairment charges may result from declines in oil, NGLs and natural gas prices. For the years ended December 31, 2015, 2014 and 2013, we recorded \$1.6 billion, \$247.7 million and no impairment, respectively, of non-cash impairment charges as a result of the full cost ceiling limitation.

We could have a future reduction in asset carrying value for oil and natural gas properties if the average of the unweighted first day of the month oil and natural gas prices for the prior twelve month period declines. For example, as of December 31, 2015, the unweighted average of the historical first day of the month pricing for oil and natural gas were \$50.28 per Bbl and \$2.58 per MMbtu, respectively, compared to \$46.26 per Bbl and \$2.39 per MMbtu for oil and natural gas, respectively, in March 2016. Holding all other factors constant, if commodity prices used in our year-end reserve estimates were decreased by \$4.02 per Bbl for crude oil and \$0.19 per Mcf for natural gas, thereby approximating the pricing environment existing in March 2016, our estimated discounted future cash flows from proved reserves at December 31, 2015 would decrease by approximately \$69 million, or 14%. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties and otherwise if impairment has occurred. In addition, we analyze our unevaluated leasehold and transfer to evaluated properties leasehold that can be associated with proved reserves, leasehold that expired in the quarter or leasehold that is

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not a part of our development strategy and will be abandoned. As of December 31, 2015 the Company has no unevaluated properties excluded from the full cost pool.

We evaluate gas gathering and processing equipment for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the years ended December 31, 2015, 2014 and 2013, we recorded no impairment, $1.7 million and no impairment, respectively, based on expected present value and estimated future cash flows using current volume throughput and pricing assumptions. Additionally, for the years ended December 31, 2015, 2014 and 2013, we recorded impairment charges for other assets of $1.1 million, $0.2 million and $1.1 million, respectively.

Goodwill is tested for impairment on an annual basis as of October 1 of each year and more frequently if changes in circumstances warrant. Due to a drop in commodity prices and the $247.7 million ceiling impairment in 2014, a December 31, 2014 impairment test was also performed and resulted in the impairment of our $173.5 million of goodwill for the year ended December 31, 2014. No goodwill remains as of December 31, 2015 and 2014.

- Other operating expenses. Other operating expenses consist primarily of transaction costs related to the Combination.
- Interest. During the periods presented, we have historically financed a portion of our working capital requirements and acquisitions with borrowings under the Former Revolving Credit Facility, the New Revolving Credit Facility and the Term Loan Facility. As a result, we incurred interest expense that was affected by the level of drilling, completion and acquisition activities, as well as fluctuations in interest rates and our financing decisions. We also incurred interest expense on our 2017 Notes, and, for the period following the completion of the Combination on December 16, 2014, the 2019 Notes and 2020 Notes. As of March 21, 2016, the total outstanding principal amount of our long-term indebtedness was $2.752 billion, consisting of indebtedness under the New Revolving Credit Facility, the 2017 Notes, the Legacy Forest Notes, and the Term Loan Facility, which will continue to expose us to interest rates. As of March 21, 2016, no extensions of credit are available under the New Revolving Credit Facility. To date, we have not entered into any interest rate hedging arrangements to mitigate the effects of interest rate changes. Additionally, we capitalized $3.3 million, $6.5 million and $13.0 million of interest expense for the years ended December 31, 2015, 2014 and 2013, respectively.
- Reorganization Expense. The Company uses this category to reflect the net revenues, expenses, gains and losses that are the result of the reorganization and restructuring of the business.

Professional fees included in Reorganization items, net represent professional fees for post-petition expenses. Deferred financing costs and unamortized discounts are related to the New Revolving Credit Facility, Term Loan Facility, 2017 Notes, 2019 Notes and 2020 Notes and are included in Reorganization items, net as we believe these debt instruments may be impacted by the bankruptcy reorganization process. Terminated contracts are primarily related to the Company's rig and servicing contracts rejected on August 10, 2015 by the Court, effective July 15, 2015. For additional information, please see Note 14 to our financial statements included herein. The terminated contracts represent the estimated claims related to rejection of approved contracts that were not previously included in the balance sheet as the liability was contingent or an executory contract previously reported as commitments and contingencies. Expenses for terminated contracts were based on pre-petition general unsecured claims for damages caused by the Company's breach of contract.

During the pendency of the bankruptcy proceedings, the Company will operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. The Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") 852, Reorganizations, applies to entities that have filed a petition for bankruptcy under Chapter 11 of the Bankruptcy Code. The guidance requires that transactions and events directly associated with the reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting and presentation of liabilities, as well as expenses and income directly associated with the Chapter 11

Cases.

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· Income Tax Expense. Prior to the Combination, we were a limited liability company treated as a partnership for federal and state income tax liabilities and/or benefits of Sabine O&G being passed through to its member. Accordingly, no provision for federal or state income taxes was recorded for the year ended December 31, 2013 prior to the Combination as our equity holders were responsible for income tax on our profits. In connection with the completion of the Combination, we merged into a corporation and became subject to federal and state income taxes. Our book and tax basis in assets and liabilities differed at the time of our change in tax status due primarily to different cost recovery periods utilized for book and tax purposes for our oil and natural gas properties.

For the year December 31, 2014, we recorded total income tax expense of $35 million. The significant differences between our blended federal and state statutory income tax rate of 36% were primarily due to earnings prior to the corporate merger that are not subject to corporate income tax, recording the initial book and tax basis differences associated with the change in tax status, and impairment of non-deductible goodwill and changes in the valuation allowance. For the year December 31, 2015, we recorded total income tax expense of $3.1 million attributable to an increase in the valuation allowance which offsets the additional deferred tax assets recorded through purchase accounting for Forest. The significant differences between our blended and state statutory income tax rate of 35.5% were primarily due to the change in the Company's full valuation allowance recorded against the net deferred tax asset balance, changes in estimate for the 2014 period and state income taxes.

Significant Transactions

Other than the Combination, which is described under "The Combination" above, the following table presents a summary of our significant property acquisitions from 2013 through 2015:

Primary locations of acquired properties	Transaction Date	Purchase Price (in millions)	
North Texas – Granite Wash (TX)	June 2014	$	18
North Texas – Granite Wash (TX)	March 2014	$	20
South Texas – Eagleford Shale (TX)	April 2013	$	15

Our acquisitions were financed with a combination of funding from equity contributions from sponsors, borrowings under the Former Revolving Credit Facility and Term Loan Facility and cash flow from operations. Because of our substantial recent acquisition activity, the discussion and analysis of our historical financial condition and results of operations for the periods discussed below may not necessarily be comparable with or applicable to future results of operations. Our historical results include the results from recent acquisitions beginning on the closing dates indicated in the table above.

In 2015 we sold our working interest in various oil and gas properties in our non-core areas at auction for approximately $6.4 million. In December 2013, we sold our working interest in approximately 27,000 net acres in the Texas Panhandle and surrounding Oklahoma areas (including the Cleveland Sands assets acquired in 2012) for an adjusted purchase price of approximately $169 million.

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Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

The following table sets forth selected operating data for the year ended December 31, 2015 compared to the year ended December 31, 2014:

	For the Year Ended December 31, 2015 (in thousands)	2014	Amount of Increase (Decrease)	Percent Change	
Revenues					
Oil, natural gas liquids and natural gas	$ 334,984	$ 462,363	$ (127,379)	(28)	%
Other	2,227	2,360	(133)	(6)	%
Total revenues	337,211	464,723	(127,512)	(27)	%
Operating expenses					
Lease operating	88,855	51,262	37,593	73	%
Marketing, gathering, transportation and other	33,901	23,621	10,280	44	%
Production and ad valorem taxes	17,592	18,161	(569)	(3)	%
General and administrative	42,687	30,373	12,314	41	%
Depletion, depreciation and amortization	182,417	189,516	(7,099)	(4)	%
Accretion	1,930	958	972	101	%
Impairments	1,576,728	423,092	1,153,636		*
Other operating expenses	24,431	25,583	(1,152)		*
Total operating expenses	1,968,541	762,566	1,205,975	158	%
Other income (expenses)					
Interest, net of capitalized interest (2)	(180,285)	(115,559)	64,726	56	%
Gain on derivative instruments	33,897	121,669	87,772		*
Total other income (expenses)	(146,388)	6,110	152,498		*
Reorganization items, net	(458,838)	—	(458,838)		*
Net loss before income taxes	(2,236,556)	(291,733)	(1,944,823)		*
Income tax expense	(3,087)	(34,987)	31,900		*
Net loss	$ (2,239,643)	$ (326,720)	$ (1,912,923)		*
Reconciliation to derive Adjusted EBITDA (1):					
Interest, net of capitalized interest	180,285	115,559			
Depletion, depreciation and amortization	182,417	189,516			
Impairments	1,576,728	423,092			
Other	19,609	25,929			
Accretion	1,930	958			
Loss (gain) on derivative instruments	62,790	(120,848)			
Option premium amortization	(4,645)	(11,593)			
Reorganization items, net	458,838	—			
Income tax expense	3,087	34,987			
Adjusted EBITDA (1)	$ 241,396	$ 330,880			

* Not meaningful or applicable

(1) Adjusted EBITDA is a non-GAAP financial measure. Please see "—Non-GAAP Financial Measure."
(2) Interest at contractual interest rates would have been $193.5 million for 2015. As of the petition date, interest is no longer being accrued on the Term Loan Facility, 2017 Notes, 2019 Notes and 2020 Notes.

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	For the Year Ended December 31, 2015	2014	Amount of Increase (Decrease)	Percent Change
Oil, NGL and natural gas sales by product (in thousands):				
Oil	$ 120,996	$ 181,313	$ (60,317)	(33) %
NGL	41,610	62,420	(20,810)	(33) %
Natural gas	172,378	218,630	(46,253)	(21) %
Total	$ 334,984	$ 462,363	$ (127,380)	(28) %
Production data:				
Oil (MBbl)	2,786.40	2,169.52	616.88	28 %
NGL (MBbl)	3,168.98	2,120.56	1,048.42	49 %
Natural gas (Bcf)	66.22	49.22	17.00	35 %
Combined (Bcfe) (1)	101.95	74.96	26.99	36 %
Average prices before effects of economic hedges (2):				
Oil (per Bbl)	$ 43.42	$ 83.57	$ (40.15)	(48) %
NGL (per Bbl)	$ 13.13	$ 29.44	$ (16.31)	(55) %
Natural gas (per Mcf)	$ 2.60	$ 4.44	$ (1.84)	(41) %
Combined (per Mcfe) (1)	$ 3.29	$ 6.17	$ (2.88)	(47) %
Average realized prices after effects of economic hedges (2):				
Oil (per Bbl)	$ 60.83	$ 81.79	$ (20.97)	(26) %
NGL (per Bbl)	$ 13.13	$ 29.44	$ (16.31)	(55) %
Natural gas (per Mcf)	$ 3.26	$ 4.30	$ (1.04)	(24) %
Combined (per Mcfe)(1)	$ 4.19	$ 6.02	$ (1.84)	(30) %
Average costs (per Mcfe) (1):				
Lease operating	$ 0.87	$ 0.68	$ 0.19	28 %
Marketing, gathering, transportation and other	$ 0.33	$ 0.32	$ 0.01	3 %
Production and ad valorem taxes	$ 0.17	$ 0.24	$ (0.07)	(29) %
General and administrative	$ 0.42	$ 0.41	$ 0.01	2 %
Depletion, depreciation and amortization	$ 1.79	$ 2.53	$ (0.74)	(29) %

(1) Oil and NGL production was converted at 6 Mcf per Bbl to calculate combined production and per Mcfe amounts.

(2) Average prices shown in the table reflect prices both before and after the effects of cash settlements on commodity derivative transactions. The Company’s calculation of such effects includes gains or losses on cash settlements for commodity derivative transactions.

Oil, natural gas liquids and natural gas sales. Revenues from production of oil and natural gas decreased from $462.4 million in 2014 to $335.0 million in 2015, a decrease of 28%. This decrease of $127.4 million was primarily the result of a decrease in oil, natural gas liquids and natural gas revenues of $60.3 million, $20.8 million and $46.3 million, respectively, due to a decrease in prices of $40.15/Bbl, $16.31/Bbl and $1.84/Mcf, respectively. These decreases were partially offset by a 36% increase in production, primarily due to the Combination and our East Texas development activities.

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The following table sets forth additional information concerning our production volumes for the year ended December 31, 2015 compared to the year ended December 31, 2014:

	For the Year Ended December 31,		Percent Change
	2015	2014	
	(in Bcfe)		
South Texas	19.96	22.65	(12) %
East Texas	72.76	44.39	64 %
North Texas	9.23	7.92	16 %
Total	101.95	74.96	36 %

Lease operating. Lease operating expenses increased from $51.3 million in 2014 to $88.9 million in 2015, an increase of 73%. The increase in lease operating expense of $37.6 million is primarily due to an increase in producing properties as a result of the Combination. Lease operating expenses increased from $0.68 per Mcfe in 2014 to $0.87 per Mcfe in 2015. The increase of $0.19 per Mcfe in the year ended December 31, 2015 versus the year ended December 31, 2014 is primarily due to higher cost legacy Forest production. The following table displays the lease operating expense by area for the years ended December 31, 2015 and 2014:

	For the Year Ended December 31,		December 31,	
	2015	Per Mcfe	2014	Per Mcfe
	(in thousands, except per Mcfe data)			
South Texas	$ 18,737	$ 0.94	$ 8,185	$ 0.36
East Texas	66,961	0.92	40,089	0.94
North Texas	3,157	0.34	3,008	0.38
Other	—	—	(20)	—
Total	$ 88,855	$ 0.87	$ 51,262	$ 0.68

Marketing, gathering, transportation and other. Marketing, gathering, transportation and other expenses increased from $23.6 million in 2014 to $33.9 million in 2015, an increase of 44%. Marketing, gathering, transportation and other expenses increased on a per unit basis from $0.32 per Mcfe in 2014 to $0.33 per Mcfe in 2015. The increase of $10.3 million in the year ended December 31, 2015 versus the year ended December 31, 2014 is primarily due to increased processing of gas volumes associated with our development activities throughout 2014 and 2015, coupled with increasing oil volumes associated with development activities and the Combination.

Production and ad valorem taxes. Production and ad valorem taxes decreased from $18.2 million in 2014 to $17.6 million in 2015, a decrease of 3%. Production and ad valorem taxes decreased on a per unit basis from $0.24 per Mcfe in 2014 to $0.17 per Mcfe in 2015. The decrease of $0.07 per Mcfe in the year ended December 31, 2015 versus the year ended December 31, 2014 is primarily due to lower pricing of 48% per Bbl for oil and 41% per Mcf for natural gas, coupled with processing high cost gas exemptions in 2015, partially offset by increased production associated with the Combination. We expect to experience continued variability in our production taxes as a result of timing of approval for high cost gas tax exemptions. Production and ad valorem taxes as a percentage of oil and natural gas revenues were 5% and 4% for 2015 and 2014, respectively.

General and administrative. General and administrative expenses increased from $30.4 million in 2014 to $42.7 million in 2015, an increase of $12.3 million, or 41%, primarily as a result of higher overhead associated with the Combination. General and administrative expenses increased on a per unit basis from $0.41 per Mcfe in 2014 to $0.42 per Mcfe in 2015.

Depletion, depreciation and amortization. DD&A decreased from $189.5 million in 2014 to $182.4 million in 2015, a decrease of $7.1 million. DD&A decreased from $2.53 per Mcfe in 2014 to $1.79 per Mcfe in 2015, or a decrease of 4%. The decrease in the DD&A rate per Mcfe is driven by a lower amortization base due to recent ceiling test impairments resulting from declines in the prior 12 month pricing and lower PV-10 estimates compared to net book value, coupled with increased total reserves from the Combination.

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Impairments. In 2015, as a result of a decrease in commodity pricing, there were non-cash impairment charges related to oil and natural gas properties of $1.6 billion and impairment charges for other assets of $1.1 million. In 2014, there were non-cash impairment charges related to oil and gas properties of $247.7 million, impairment charges for gas gathering and processing equipment of $1.7 million and impairment charges for other assets of $0.2 million. Additionally, due to a drop in commodity prices and the $247.7 million ceiling impairment in 2014 the Company tested goodwill for impairment. At December 31, 2014 goodwill impairment test resulted in the impairment of our $173.5 million of goodwill for the year ended December 31, 2014.

Other operating expenses. Other operating expenses in 2015 consist primarily of $19.8 million of transaction costs related to the Combination and $2.9 million of charges related to marketing contract volume commitments. Other operating expenses in 2014 consist primarily of $25.5 million of transaction costs related to the Combination and $2.0 million for the write-off of previously deferred public offering costs related to offerings which were aborted prior to our decision to commence the Combination, partially offset by the gain on a sale of other assets of $1.5 million.

Interest expense. Interest expense increased from $115.6 million in the year ended December 31, 2014 to $180.3 million in the year ended December 31, 2015, an increase of $64.7 million, or 56%, primarily as a result of increased borrowings on the New Revolving Credit Facility, the assumption of the 2019 Notes and 2020 Notes in connection with the consummation of the Combination on December 16, 2014 and increased amortization of associated debt discounts. No interest expense has been recognized subsequent to the petition date on the Term Loan, 2017 Notes, 2019 Notes or the 2020 Notes.

Gain on derivative instruments. Gains from the change in fair value of derivative instruments as well as cash settlements on commodity derivatives are recognized in our results of operations. During the years ended December 31, 2015 and 2014, we recognized net gains on derivative instruments of $33.9 million and $121.7 million, respectively. The Company's Bankruptcy Petition in July 2015 represented an event of default under Sabine's existing derivative agreements resulting in a termination right by counterparties on all derivative positions at July 15, 2015. Additionally, certain of the Company's derivative positions were terminated prior to July 15, 2015 as a result of defaults under Sabine's derivative agreements that occurred prior to the filing of the Bankruptcy Petition.

Reorganization Items, net. Professional fees included in Reorganization Items, net represent professional fees incurred for post-petition expenses which would not have otherwise been incurred by the Company and are presented as reorganization items. Terminated contracts represent the estimated claims related primarily to rig and servicing contracts, certain office leases and other executory contracts, and were not previously included in the Consolidated Balance Sheets as the liability was contingent in nature or other executory contracts included in commitments and contingencies.

	For the Year Ended December 31, 2015 (in thousands)
Professional fees	$ 46,117
Deferred financing costs & unamortized discounts	378,705
Terminated contracts	33,197
Interest	(157)
Other	976

Total Reorganization items, net	$ 458,838

Income Tax Expense. Prior to the Combination, no provision for federal or state income taxes was recorded, as we were a limited liability company and not subject to federal or state income tax. In connection with the completion of the Combination, we merged into a corporation and became subject to federal and state income taxes. For December 31, 2014, we recorded an estimated net deferred tax expense of $35.0 million to recognize a deferred tax liability for the initial book and tax basis difference associated with the change in tax status, impairment of a non-deductible goodwill and changes in the valuation allowance associated with the Combination. We recorded an additional deferred tax expense of $3.1 million in December 2015 for adjustments related to the net deferred tax expense estimate recorded in December 2014.

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Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

The following table sets forth selected operating data for the year ended December 31, 2014 compared to the year ended December 31, 2013:

	For the Year Ended December 31, 2014	2013	Amount of Increase (Decrease)	Percent Change	
	(in thousands)				
Revenues					
Oil, natural gas liquids and natural gas	$ 462,363	$ 354,223	$ 108,140	31	%
Other	2,360	755	1,605	213	%
Total revenues	464,723	354,978	109,745	31	%
Operating expenses					
Lease operating	51,262	44,620	6,642	15	%
Marketing, gathering, transportation and other	23,621	17,567	6,054	34	%
Production and ad valorem taxes	18,161	17,824	337	2	%
General and administrative	30,373	27,469	2,904	11	%
Depletion, depreciation and amortization	189,516	137,068	52,448	38	%
Accretion	958	952	6	1	%
Impairments	423,092	1,125	421,967		*
Other operating expenses (income)	25,583	(858)	26,441		*
Total operating expenses	762,566	245,767	516,799	210	%
Other income (expenses)					
Interest, net of capitalized interest	(115,586)	(99,471)	16,115	16	%
Gain on derivative instruments	121,669	814	(120,855)		*
Other income	27	23	(4)		*
Total other income (expenses)	6,110	(98,634)	(104,744)		*
Net income (loss), including noncontrolling interests	(291,733)	10,577	(302,310)		*
Income tax expense	(34,987)	—	(34,987)		*
Net income (loss) applicable to controlling interests	$ (326,720)	$ 10,577	$ (337,297)		*
Reconciliation to derive Adjusted EBITDA (1):					
Interest, net of capitalized interest	115,586	99,471			
Depletion, depreciation and amortization	189,516	137,068			
Impairments	423,092	1,125			
Other	25,974	1,739			
Amortization of deferred rent	(72)	(249)			
Accretion	958	952			
Loss (gain) on derivative instruments	(120,848)	46,545			
Option premium amortization	(11,593)	(1,171)			
Income tax expense	34,987	—			
Adjusted EBITDA (1)	$ 330,880	$ 296,057			

* Not meaningful or applicable

(1) Adjusted EBITDA is a non-GAAP financial measure. Please see “—Non-GAAP Financial Measure.”

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	For the Year Ended December 31, 2014	2013	Amount of Increase (Decrease)	Percent Change
Oil, NGL and natural gas sales by product (in thousands):				
Oil	$ 181,313	$ 132,513	$ 48,800	37 %
NGL	62,420	59,772	2,648	4 %
Natural gas	218,630	161,938	56,692	35 %
Total	$ 462,363	$ 354,223	$ 108,140	31 %
Production data:				
Oil (MBbl)	2,169.52	1,403.62	765.90	55 %
NGL (MBbl)	2,120.56	1,842.47	278.09	15 %
Natural gas (Bcf)	49.22	44.29	4.93	11 %
Combined (Bcfe) (1)	74.96	63.77	11.19	18 %
Average prices before effects of economic hedges (2):				
Oil (per Bbl)	$ 83.57	$ 94.41	$ (10.84)	(11) %
NGL (Bbl)	$ 29.44	$ 32.44	$ (3.00)	(9) %
Natural gas (per Mcf)	$ 4.44	$ 3.66	$ 0.78	21 %
Combined (per Mcfe) (1)	$ 6.17	$ 5.55	$ 0.62	11 %
Average realized prices after effects of economic hedges (2):				
Oil (per Bbl)	$ 81.79	$ 90.49	$ (8.70)	(10) %
NGL (Bbl)	$ 29.44	$ 32.44	$ (3.00)	(9) %
Natural gas (per Mcf)	$ 4.30	$ 4.82	$ (0.52)	(11) %
Combined (per Mcfe) (1)	$ 6.02	$ 6.28	$ (0.26)	(4) %
Average costs (per Mcfe) (1):				
Lease operating	$ 0.68	$ 0.70	$ (0.02)	(3) %
Marketing, gathering, transportation and other	$ 0.32	$ 0.28	$ 0.04	14 %
Production and ad valorem taxes	$ 0.24	$ 0.28	$ (0.04)	(14) %
General and administrative	$ 0.41	$ 0.43	$ (0.02)	(5) %
Depletion, depreciation and amortization	$ 2.53	$ 2.15	$ 0.38	18 %

(1) Oil and NGL production was converted at 6 Mcf per Bbl to calculate combined production and per Mcfe amounts.

(2) Average prices shown in the table reflect prices both before and after the effects of cash settlements on commodity derivative transactions. The Company's calculation of such effects includes gains or losses on cash settlements for commodity derivative transactions.

Oil, natural gas liquids and natural gas sales. Revenues from production of oil and natural gas increased from $354.2 million in 2013 to $462.4 million in 2014, an increase of 31%. This increase of $108.1 million was primarily the result of an increase in oil, natural gas liquids and natural gas revenues of $48.8 million, $2.6 million and $56.7 million, respectively, due to an increase in production in South Texas through an active and successful development program in this region as well as an increase in realized price for natural gas of 21%. These increases were partially offset by the December 2013 sale of our interests in certain oil and natural gas properties in the Texas Panhandle and surrounding Oklahoma area and a decrease in realized price for oil of 11%.

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The following table sets forth additional information concerning our production volumes for the year ended December 31, 2014 compared to the year ended December 31, 2013:

	For the Year Ended December 31, 2014	2013	Percent Change	
	(in Bcfe)			
South Texas	22.65	9.89	129	%
East Texas	44.39	42.05	6	%
North Texas	7.92	11.83	(33)	%
Total	74.96	63.77	18	%

Lease operating expenses. Lease operating expenses increased from $44.6 million in 2013 to $51.3 million in 2014, an increase of 15%. The increase in lease operating expense of $6.6 million is primarily due to an increase in producing properties as a result of development activities in South Texas partially offset by the December 2013 sale of our interests in certain oil and natural gas properties in the Texas Panhandle and surrounding Oklahoma area. Lease operating expenses decreased from $0.70 per Mcfe in 2013 to $0.68 per Mcfe in 2014. The decrease of $0.02 per Mcfe in the year ended December 31, 2014 versus the year ended December 31, 2013 is primarily due to the December 2013 sale of our interests in certain oil and natural gas properties in the Texas Panhandle and surrounding Oklahoma area with offsetting increases in South Texas and East Texas as a result of increasing development activities. The following table displays the lease operating expense by area for the years ended December 31, 2014 and 2013:

	For the Year Ended December 31, 2014	Per Mcfe	December 31, 2013	Per Mcfe
	(in thousands, except per Mcfe data)			
South Texas	$ 8,185	$ 0.36	$ 2,266	$ 0.23
East Texas	40,089	0.94	36,183	0.86
North Texas	3,008	0.38	6,162	0.52
Other	(20)	—	9	—
Total	$ 51,262	$ 0.68	$ 44,620	$ 0.70

Marketing, gathering, transportation and other. Marketing, gathering, transportation and other expenses increased from $17.6 million in 2013 to $23.6 million in 2014 an increase of 34%. Marketing, gathering, transportation and other expense increased on a per unit basis from $0.28 per Mcfe in 2013 to $0.32 per Mcfe in 2014. The increase of $0.04 per Mcfe in the year ended December 31, 2014 versus the year ended December 31, 2013 is primarily due to increased processing of gas volumes associated with our South Texas development activities as well as gas volumes associated with our Haynesville development activities in East Texas, which were subject to higher fees due to lack of pipeline infrastructure, partially offset by decreases in the average rate per Mcfe due to the December 2013 sale of our interests in certain oil and gas properties in the Texas Panhandle and surrounding Oklahoma area coupled with increasing oil volumes associated with development activities in that area.

Production and ad valorem taxes. Production and ad valorem taxes increased from $17.8 million in 2013 to $18.2 million in 2014, an increase of 2%. Production and ad valorem taxes decreased on a per unit basis from $0.28 per Mcfe in 2013 to $0.24 per Mcfe in 2014. The decrease of $0.04 per Mcfe in the year ended December 31, 2014 versus the year ended December 31, 2013 is primarily due to a decrease in North Texas production due to the December 2013 sale of our interests in certain oil and natural gas properties in the Texas Panhandle and surrounding Oklahoma area. This decrease in the rate per Mcfe is partially offset by increases in production tax expenses primarily due to increased production in the South Texas region which is incurring higher production taxes on oil, natural gas liquids and natural gas production. We expect to experience continued variability in our production taxes as a result of timing of approval for high cost gas tax exemptions. Production and ad valorem taxes as a percentage of oil and natural gas revenues were 4% and 5% for 2014 and 2013, respectively.

General and administrative expenses. General and administrative expenses increased from $27.5 million in 2013 to $30.4 million in 2014, an increase of $2.9 million, or 11%, as a result of higher overhead associated with our growing business. General and administrative expenses decreased on a per unit basis from $0.43 per Mcfe in 2013 to $0.41 per Mcfe in 2014 production without a proportionate increase in general and administrative expenses.

Depletion, depreciation and amortization (DD&A). DD&A increased from $137.1 million in 2013 to $189.5 million in 2014, an increase of $52.4 million. Depletion, depreciation, and amortization increased from $2.15 per Mcfe in 2013 to $2.53 per Mcfe in 2014, or an increase of 18%. The increase in the DD&A rate per Mcfe is driven by reductions to proved reserves due to the sale of certain oil and natural gas properties in North Texas during the fourth quarter of 2013 as well as an increase in the amortization base as a result of development activities without a proportionate increase in reserve volumes.

Impairments. In 2014, there were non-cash impairment charges related to oil and natural gas properties of $247.7 million, impairment charges for gas gathering and processing equipment of $1.7 million and impairment charges for other assets of $0.2 million. Additionally, due to a drop in commodity prices and the $247.7 million ceiling impairment, a December 31, 2014 goodwill impairment test resulted in the impairment of our $173.5 million of goodwill for the year ended December 31, 2014. In 2013, there were impairment charges for other assets of $1.1 million. There were no impairments related to oil and natural gas properties recognized in 2013 as a result of favorable unweighted average of the historical first day of the month pricing for the year ended December 31, 2013 of $3.67 per MMbtu as compared to $2.76 per MMbtu for the year ended December 31, 2013 as well as favorable performance from our 2013 development activities.

Other operating expenses. Other operating expenses in 2014 relate primarily to $25.5 million of transaction costs related to the Combination and $2.0 million for the write-off of previously deferred public offering costs related to offerings which were aborted prior to our decision to commence the Combination, partially offset by the gain on sale of other assets of $1.5 million, as compared to $0.9 million of other operating income for the year ended December 31, 2013.

Interest expense. Interest expense increased from $99.5 million in the year ended December 31, 2013 to $115.6 million in the year ended December 31, 2014, an increase of $16.1 million, or 16%, primarily as a result of increased borrowings on the New Revolving Credit Facility and $5.8 million of interest expense on the 2019 Notes and 2020 Notes. Additionally, capitalized interest has decreased due to reclassification of unproved oil and natural gas properties in 2014 into the full cost pool as a result of development activities or impairments due to lease expirations and abandonments. We capitalized $6.5 million and $13.0 million of interest expense for the years ended December 31, 2014 and 2013, respectively.

Gain on derivative instruments. Gains and losses from the change in fair value of derivative instruments as well as cash settlements on commodity derivatives are recognized in our results of operations. During the years ended December 31, 2014 and 2013, we recognized net gains on derivative instruments of $121.7 million and $0.8 million, respectively.

Income Tax Expense. Prior to the Combination, no provision for federal or state income taxes was recorded, as we were a limited liability company and not subject to federal or state income tax. In connection with the completion of the Combination, we merged into a corporation and became subject to federal and state income taxes. For December 31, 2014, we recorded an estimated net deferred tax expense of $35 million to recognize a deferred tax liability for the initial book and tax basis difference associated with the change in tax status, impairment of a non-deductible goodwill and changes in the valuation allowance.

Capital Resources and Liquidity

Our primary sources of liquidity have historically been equity contributions, borrowings under the New Revolving Credit Facility, net cash provided by operating activities, net proceeds from the issuance of the 2017 Notes and proceeds from the Term Loan Facility. Our primary use of capital has been the acquisition and development of oil and natural gas properties. Since the Chapter 11 filings, our principal sources of liquidity have been limited to cash flow from operations and cash on hand. In addition to the cash requirements necessary to fund ongoing operations, we have incurred and continue to incur significant professional fees and other costs in connection with the preparation and administration of the Chapter 11 Cases. We anticipate that we will continue to incur significant professional fees and costs for the pendency of the Chapter 11 Cases.

Subsequent to December 31, 2015 we have not entered into additional derivative contracts. Additionally, the filing of our Bankruptcy Petition in July 2015 represented an event of default under our derivative agreements resulting in a termination right by counterparties on all derivative positions at July 15, 2015. Certain of the Company's derivative positions were terminated prior to July 15, 2015 as a result of defaults under Sabine's derivative agreements that occurred prior to the filing of the Bankruptcy Petition. The terminations resulted in settlements of approximately $24.3 million for which such proceeds were used to reduce the amount of borrowing outstanding under our New Revolving Credit Facility. Other terminations resulted in approximately $70.8 million of direct offsets against the New Revolving Credit Facility. As a result, the Company no longer has any derivatives beyond July 2015.

Although we believe our cash flow from operations and cash on hand will be adequate to meet the operating costs of our existing business, there are no assurances that our cash flow from operations and cash on hand will be sufficient to continue to fund our operations or to allow us to continue as a going concern until a Chapter 11 plan is confirmed by the Bankruptcy Court or another alternative restructuring transaction is approved by the Bankruptcy Court and consummated. Our long-term liquidity requirements, the adequacy of our capital resources and our ability to continue as a going concern are difficult to predict at this time and ultimately cannot be determined until a Chapter 11 plan has been confirmed, if at all, by the Bankruptcy Court. If our future sources of liquidity are insufficient, we could face substantial liquidity constraints and be unable to continue as a going concern and will likely be required to significantly reduce, delay or eliminate capital expenditures, implement further cost reductions, seek other financing alternatives or seek the sale of some or all of our assets. The Company has temporarily deferred additional development activities. If we (i) continue to limit, defer or eliminate future capital expenditure plans, (ii) are unsuccessful in developing reserves and adding production through our capital program or (iii) implement cost-cutting efforts that are too overreaching, the value of our oil and natural gas properties and our financial condition and results of operations could be adversely affected.

In connection with funding our liquidity and the Combination, we have incurred substantial additional debt. As of December 31, 2015, the total outstanding principal amount of our long-term indebtedness was $2.752 billion, consisting of indebtedness under the New Revolving Credit Facility, the 2017 Notes, the Legacy Forest Notes, and the Term Loan Facility, and, as of December 31, 2015, no extensions of credit are available under the New Revolving Credit Facility. In addition, our filing of the Bankruptcy Petitions constituted an event of default that accelerated our obligations under these debt instruments. For a description of our outstanding debt instruments, please see "—Net Cash Provided by Financing Activities." The stay under the Bankruptcy Code does not apply to letters of credit and third parties may continue do draw on their letters of credit.

Our ability to service our debt obligations and fund our capital expenditures has been negatively impacted by significant decreases in the market price for oil, NGLs and natural gas during the fourth quarter of 2014 with continued weakness throughout 2015. The decrease in the market price for our production directly reduces our operating cash flow. While we historically used hedging arrangements to reduce our exposure to fluctuations in the prices of oil, NGLs and natural gas, none of our production is hedged and we may be unable to effectively hedge our production for future periods. In addition, the decrease in the market price for our production indirectly impacts our other sources of potential liquidity.

On February 25, 2015, we borrowed $356 million under our New Revolving Credit Facility which represented the remaining undrawn amount under the New Revolving Credit Facility. Our borrowing base under our New Revolving Credit Facility was subject to its semi-annual redetermination on April 27, 2015 and was decreased to $750 million. The decrease in our borrowing base as a result of the redetermination resulted in a deficiency of approximately $250 million which required repayment in six monthly installments in an amount of $41.54 million, beginning May 27,

2015. None of such payments has been made or will be made and pursuant to the automatic stay under the Bankruptcy Code, the creditors under the New Revolving Credit Facility are currently stayed from taking any action against us as a result of these non-payments. Our cash balance at March 21, 2016 was approximately $173.0 million.

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Ability to Continue as a Going Concern

Our filing of the Bankruptcy Petitions described above accelerated our obligations under the New Revolving Credit Facility, the Term Loan Facility, the 2017 Notes and the Legacy Forest Notes. We have classified all debt as "Liabilities Subject to Compromise" in the Consolidated Balance Sheet at December 31, 2015. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and the reported income and expenses could be required and would be material. For additional description of the defaults present under our debt obligations, please see Note 8 within "Part II, Item 8. Financial Statements and Supplementary Data."

Working Capital

Our working capital balance fluctuates as a result of timing and amount of borrowings or repayments under our credit arrangements, changes in the fair value of our outstanding commodity derivative instruments, the timing of receiving reimbursement of amounts paid by us for the benefit of joint venture partners as well as changes in revenue receivables as a result of price and volume fluctuations.

For the year ended December 31, 2015, we had an increase in working capital of $2.2 billion. The increase in working capital is primarily due to the reclassification of our debt from "Current maturities of long-term debt" to "Liabilities Subject to Compromise" in the Consolidated Balance Sheets at December 31, 2015. In addition, fluctuations are due to the timing and amount of the receivable collections, development activities, payments made by us to vendors, and the timing and amount of advances from our joint operations. For more information on the classification of debt, please see Note 8 within "Part II, Item 8. Financial Statements and Supplementary Data."

Cash Flow Provided by Operating Activities

Cash flows from operations are our primary source of capital and liquidity and are primarily affected by the sale of oil, NGLs and natural gas, as well as commodity prices, net of effects of derivative contract settlements and changes in working capital. Net cash provided by operating activities was $134.4 million, $209.2 million and $217.2 million for the years ended December 31, 2015, 2014 and 2013, respectively. The decrease in cash flow from operations for the year ended December 31, 2015 as compared to 2014 was primarily the result of decrease in prices, higher interest payments and costs incurred for the Combination and costs incurred in the Chapter 11 Cases. A substantial portion of 2015 cash flow (approximately $76 million) was also derived from changes in working capital during the year. The decrease in cash flow from operations for the year ended December 31, 2014 compared to 2013 was primarily the result of the excess in cash outflows for settlements of derivatives, higher interest payments, costs incurred for the Combination and the December 2013 sale of our interests in certain oil and natural gas properties in the Texas Panhandle and surrounding Oklahoma, offset by greater cash proceeds due to 18% higher volumes and 11% higher realized prices.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for oil and natural gas production. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Part II, Item 7A. Quantitative and Qualitative Disclosure About Market Risk" below.

Cash Flow Used in Investing Activities

During the years ended December 31, 2015, 2014 and 2013, cash flows used in investing activities were $329.4 million, $438.6 million and $193.8 million, respectively, primarily related to capital expenditures for drilling, development and acquisition costs. The decrease in cash flows used in investing activities during the year ended December 31, 2015 compared to 2014 was primarily the result of reduced development activities. The increase in cash flows used in investing activities during the year ended December 31, 2014 compared to 2013 was primarily the result of increased capital expenditures incurred in the 2014 drilling program over 2013, partially offset by cash received in the Combination with Forest. Further, in 2013 we collected $171.8 million in cash proceeds from the sale of assets, versus $17.3 million collected in 2014.

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Our capital expenditures for drilling, development and acquisition costs for the years ended December 31, 2015, 2014 and 2013 are summarized in the following table:

	For the Year Ended December 31,		
	2015	2014	2013
	(in millions)		
South Texas	$ 21	$ 337	$ 272
East Texas	171	120	55
North Texas	16	144	104
Total capital expenditures for drilling, development and acquisitions	$ 208	$ 601	$ 431

Our planned 2016 capital expenditures budget is expected to total approximately $18 million. The amount, timing and allocation of capital expenditures are largely discretionary and within our control. If oil and natural gas prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control. The temporary reduction in our capital program could result in a decline in our oil and natural gas reserves and production and cash flows and limit our ability to obtain needed capital or financing. Refer to the “Capital Resources and Liquidity” section above for a discussion of our liquidity and planned actions.

Cash Flow Provided by (Used in) Financing Activities

Net cash provided by financing activities of $400.4 million during the year ended December 31, 2015 was primarily the result of net borrowings under the New Revolving Credit Facility of $401.7 million offset by debt issuance costs of $1.1 million. Net cash provided by financing activities of $220.8 million during the year ended December 31, 2014 was primarily the result of net borrowings under the New Revolving Credit Facility of $240.0 million offset by debt issuance costs of $19.2 million. Net cash used in financing activities of $17.8 million during the year ended December 31, 2013 was primarily the result of net repayments under the Former Revolving Credit Facility of $155.0 million and debt issuance costs of $6.3 million offset by borrowings under the Term Loan Facility of $153.5 million.

New Revolving Credit Facility. On December 16, 2014, we amended and restated the Amended and Restated Credit Agreement, dated as of April 28, 2009, maturing on April 7, 2016, by and among us, Wells Fargo Bank, National Association, as administrative agent, and the lenders and other parties party thereto with the New Revolving Credit Facility. The New Revolving Credit Facility provided for a $2 billion revolving credit facility, with an initial borrowing base of $1 billion. The New Revolving Credit Facility included a sub-limit permitting up to $100 million of letters of credit. The borrowing base for the New Revolving Credit Facility was subsequently reduced to $750 million on April 27, 2015.

On May 4, 2015, we entered into a Forbearance Agreement and First Amendment (the “NRCF Forbearance Agreement”) to the New Revolving Credit Facility to address certain events of default that were present. Pursuant to the NRCF Forbearance Agreement, the lenders agreed to forbear from exercising remedies until the earlier of (i) certain events of default under the NRCF Forbearance Agreement or the New Revolving Credit Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) June 30, 2015 (the “Initial NRCF Forbearance Period”), with respect to the following anticipated (at the time) events of default: (i) the “going concern” qualification in our 2014 audited financial statements, (ii) the failure of us to make the April 2015 interest payment due under the Term Loan Facility, and (iii) any failure of us to make the May 27, 2015 and June 27, 2015 borrowing base deficiency payments under the New Revolving Credit Facility. In exchange for the lenders agreeing to forbear, we agreed during the Initial NRCF Forbearance Period to, among other things, tighten certain covenants under the New Revolving Credit Facility and provide mortgages on certain currently unencumbered properties.

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On June 30, 2015, we entered into an Amendment (the "NRCF Forbearance Amendment") to the NRCF Forbearance Agreement. Pursuant to the NRCF Forbearance Amendment, the lenders agreed to extend the forbearance agreement to continue forbear from exercising remedies until the earlier of (i) certain events of default under the NRCF Forbearance Agreement or the New Revolving Credit Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) July 15, 2015 (the "Second Forbearance Period"), with respect to our then currently existing events of default under the New Revolving Credit Facility. In exchange for the lenders agreeing to forbear, we agreed during the Second Forbearance Period to (i) further limit our ability to sell assets, (ii) undertake efforts to appoint a chief restructuring officer, (iii) implement procedures to segregate the proceeds of collateral under the New Revolving Credit Facility and (iv) pay a forbearance fee equal to $500,000.

Our filing of the Bankruptcy Petitions described under "—Chapter 11 Filings" above constitutes an event of default, not subject to the NRCF Forbearance Agreement, that accelerated our obligations under the New Revolving Credit Facility. Additionally other events of default, including cross-defaults, are present due to the failure to make interest payments, the failure to make the borrowing base deficiency payments, the "going concern" qualification in our 2014 audited financial statements and other matters.

Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

We are making adequate protection payments to the lenders under the New Revolving Credit Facility in an amount equal to the non-default rate of interest, fees and costs due and payable on a monthly basis under the New Revolving Credit Facility, in accordance with the cash collateral order filed with the Bankruptcy Court. Additionally, cash generated by the Company deemed to be proceeds of the oil and gas properties that represent prepetition collateral is deposited into a segregated account, which is reflected as Cash in the Consolidated Balance Sheet as of December 31, 2015, and it is used solely to pay for the operations of the prepetition collateral properties.

Prior to May 29, 2015, loans under the New Revolving Credit Facility bore interest at our option at either:

· the sum of (1) the Alternate Base Rate, which is defined as the highest of (a) Wells Fargo Bank, National Association's prime rate; (b) the federal funds effective rate plus 0.50%; or (c) the Eurodollar Rate (as defined in the New Revolving Credit Facility) for a one-month interest period plus 1% and (2) a margin varying from 0.50% to 1.50% depending on our most recent borrowing base utilization percentage; or
· the Eurodollar Rate plus a margin varying from 1.50% to 2.50% depending on our most recent borrowing base utilization percentage.

Beginning May 29, 2015 and thereafter during the occurrence of an event of default under the New Revolving Credit Facility, the Loans under the New Revolving Credit Facility will bear interest at the Revolving Base Rate (as defined in the New Revolving Credit Facility.

As of December 31, 2015 and 2014, borrowings outstanding under the New Revolving Credit Facility and the Former Revolving Credit Facility totaled $902 million and $545 million, respectively, and there were zero and $29 million of outstanding letters of credit, respectively. Additionally, borrowings under the New Revolving Credit Facility had a weighted average interest rate of 4.0% and 2.4%, respectively for the twelve month periods ended December 31, 2015 and 2014.

At December 31, 2014 the New Revolving Credit Facility was presented as a current liability in the Consolidated Balance Sheets whereas the carrying value equaled the face value. As of December 31, 2015 the New Revolving Credit Facility is presented as "Liabilities Subject to Compromise," whereas the carrying value equals the face value. Interest expense continues to be recognized on the New Revolving Credit Facility subsequent to the petition date.

The unused portion of the New Revolving Credit Facility is subject to a commitment fee ranging from 0.375% to 0.50% per annum depending on the Company’s most recent bowing base utilization.

The New Revolving Credit Facility provides that all such obligations and the guarantees will be secured by a lien on at least 80% of the PV-9 of the borrowing base properties evaluated in the most recent reserve report delivered to the

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administrative agent and a pledge of all of the capital stock of our restricted subsidiaries, subject to certain customary grace periods and exceptions. The New Revolving Credit Facility has a maturity date of April 7, 2016, however, the obligations under the New Revolving Credit Facility have already been accelerated and are subject to the bankruptcy stay as a result of the filing of the Bankruptcy Petitions.

Term Loan Facility. Sabine O&G entered into a $500 million second lien term loan agreement on December 14, 2012 with a maturity date of December 31, 2018 (provided that if the 2017 Senior Notes are not refinanced to mature at least 91 days thereafter, the maturity date shall be 91 days prior to the February 15, 2017 maturity date of the 2017 Senior Notes). On January 23, 2013, the syndication was completed with an additional funding of $150 million of proceeds pursuant to the first amendment to the Term Loan Facility bringing the outstanding balance to $650 million as of December 31, 2013. Proceeds from the Term Loan Facility were used to acquire oil and natural gas properties in December 2012 and repay borrowings under the Former Revolving Credit Facility in the first quarter of 2013.

In connection with the consummation of the Combination, on December 16, 2014, we entered into an amendment to the Term Loan Facility to provide for $50 million of incremental term loans (the "Incremental Term Loans"). The Incremental Term Loans are fungible with the existing $650 million of second lien loans under the Term Loan Facility, including with respect to interest and, in the case of eurodollar borrowings, they bear interest at the Adjusted Eurodollar Rate (as defined in the Term Loan Facility) plus 7.50%, with an interest rate floor of 1.25%, and, in the case of alternate base rate borrowings, they bear interest at the Alternate Base Rate (as defined in the Term Loan Facility) plus 6.50%, with an interest rate floor of 2.25%. Any time an interest period for Loans expires during an event of default under the Term Loan Facility, such Loans will bear interest at the Term Base Rate (as defined in the Term Loan Facility). The weighted average interest rate incurred on this indebtedness for both the years ended December 31, 2015 and 2014 was 5.3% and 8.8%.

On May 20, 2015, we entered into a Forbearance Agreement and Third Amendment (the "Term Loan Forbearance Agreement") to the Term Loan Facility. Pursuant to the Term Loan Forbearance Agreement, the lenders under the Term Loan Facility agreed to forbear from exercising remedies until the earlier of (i) certain events of default under the Term Loan Forbearance Agreement or Term Loan Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) June 30, 2015 (the "Initial Term Loan Forbearance Period"), with respect to the following anticipated (at the time) events of default: (i) the "going concern" qualification in our 2014 audited financial statements and (ii) the failure of us to make the April 2015 interest payment due under the Term Loan Facility. In exchange for the lenders under the Term Loan Facility agreeing to forbear, we agreed during the Initial Term Loan Forbearance Period to, among other things, tighten certain covenants under the Term Loan Facility.

On July 8, 2015, we entered into an Amendment (the "Term Loan Forbearance Amendment") to the Term Loan Forbearance Agreement. Pursuant to the Term Loan Forbearance Amendment, the lenders agreed to extend the forbearance and to continue to forbear from exercising remedies until the earlier of (i) certain events of default under the Term Loan Forbearance Agreement or Term Loan Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) the earlier of the termination of the forbearance period under the New Revolving Credit Facility and July 15, 2015 (the "Second Term Loan Forbearance Period"), with respect to our then currently existing events of default under the Term Loan Facility. In exchange for the lenders agreeing to forbear, we agreed during the Second Term Loan Forbearance Period to, among other things, tighten certain covenants under the Term Loan Facility.

Our filing of the Bankruptcy Petitions described under "Chapter 11 Filings" above constitutes an event of default, not subject to the Term Loan Forbearance Agreement, that accelerated our obligations under the Term Loan Facility. Additionally other events of default are present due to the failure to make interest payments, the "going concern" qualification in our 2014 audited financial statements and other matters.

At December 31, 2014 the Term Loan Facility was presented as a current liability on the Consolidated Balance Sheets whereas the carrying value equaled the face value, net of discount. As of December 31, 2015 the indebtedness under the Term Loan Facility is presented as "Liabilities Subject to Compromise" in the Consolidated Balance Sheets, whereas the carrying value equals the face value. As of the petition date the Company had accrued $30.2 million of interest related to the Term Loan Facility, reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

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All of our guarantors for our New Revolving Credit Facility have guaranteed the Term Loan Facility. The obligations under the Term Loan Facility are secured by the same collateral that secures the New Revolving Credit Facility, but the liens securing such obligations are second priority liens to the liens securing the New Revolving Credit Facility. However, the validity of the liens securing the Term Loan Facility are currently in dispute pursuant to the lawsuit filed by us against the Term Loan Facility administrative agent, Wilmington Trust, N.A. For additional information, please see "Part I, Item 3. Legal Proceedings."

2017 Notes. On February 12, 2010, Sabine Oil & Gas Corporation, formerly NFR Energy LLC, and our subsidiary Sabine Oil & Gas Finance Corporation, formerly NFR Energy Finance Corporation, co-issued $200 million in 9.75% senior unsecured notes due 2017 in a private placement to qualified institutional buyers in accordance with Rule 144A of the Securities Act and to persons outside the United States in compliance with Regulation S of the Securities Act. The 2017 Notes bear interest at a rate of 9.75% per annum, payable semi-annually on February 15 and August 15 each year commencing August 15, 2010. The 2017 Notes were issued at 98.73% of par. In conjunction with the issuance of the 2017 Notes, the Company recorded a discount of $2.5 million to be amortized over the remaining life of the 2017 Notes utilizing the simple interest method. The remaining unamortized discount was $0.8 million at December 31, 2014. Discount amortization expense was $0.2 million for the year ended December 31, 2015. The remaining unamortized discount was expensed as a reorganization item. The 2017 Notes were issued under and are governed by an indenture dated February 12, 2010 by and among Sabine Oil & Gas Corporation, Sabine Oil & Gas Finance Corporation, the Bank of New York Mellon Trust Company, N.A., as trustee, and guarantors party thereto.

On April 14, 2010, Sabine Oil & Gas Corporation and Sabine Oil & Gas Finance Corporation issued an additional $150 million in senior notes at 9.75% due 2017. The additional notes were issued at 98.75% of par and bear interest at a rate of 9.75% per annum, payable semi-annually on February 15 and August 15 of each year commencing August 15, 2010. The additional notes were issued under the same indenture as the 2017 Notes issued on February 12, 2010. The Company recorded a discount of $1.9 million to be amortized over the remaining life of the 2017 Notes utilizing the simple interest method. The remaining unamortized discount was $0.6 million at December 31, 2014. Discount amortization expense was $0.1 million for the year ended December 31, 2015. The remaining unamortized discount was expensed as a reorganization item. Due to the amortization of the discount, the effective interest rate on the 2017 Notes was 5.57%.

Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

At December 31, 2014 the 2017 Notes were presented as current liabilities on the Consolidated Balance Sheets whereas the carrying value equaled the face value, net of discount. As of December 31, 2015 the 2017 Notes are presented as "Liabilities Subject to Compromise," in the Consolidated Balance Sheets whereas the carrying value equals the face value. As of the petition date the Company had accrued $14.1 million of interest related to the 2017 Notes, reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

2019 Notes. In connection with the consummation of the Combination, on December 16, 2014, the Company assumed $577.9 million in 7¼% senior notes due 2019 (the "2019 Notes") originally issued by Forest on June 6, 2007. As of the date of the Combination, the legacy Sabine O&G subsidiaries were added as guarantors to the 2019 Notes, see Note 16 for additional details. Interest on the 2019 Notes is payable semiannually on June 15 and December 15. In conjunction with the consummation of the Combination, the Company recorded the 2019 Notes at a fair value of

$290.4 million and recorded a discount of $287.5 million to be amortized over the remaining life of the 2019 Notes utilizing the simple interest method. The remaining unamortized discount was $284.9 million at December 31, 2014. Discount amortization expense was $34.4 million for the year ended December 31, 2015. The remaining unamortized discount of $250.4 million as of the Chapter 11 filing date was expensed as a reorganization item. Due to the amortization of the discount, the effective interest rate on the 2019 Notes is 9.86%.

On February 25, 2015, we received notice that Wilmington Savings Fund Society, FSB has been appointed as successor trustee under the indenture governing the 2019 Notes.

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On February 25, 2015, we received a notice of default and acceleration from the trustee with respect to our 2019 Notes and on February 26, 2015 were served a complaint alleging the same. For more information, please see "Part I, Item 3. Legal Proceedings."

The Company's filing of the Bankruptcy Petitions described in Note 2 herein constitutes an event of default that accelerated the Company's obligations under the 2019 Notes. However, under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

At December 31, 2014 the 2019 Notes were presented as current liabilities on the Consolidated Balance Sheets whereas the carrying value equaled the face value, net of discount. As of December 31, 2015 the 2019 Notes are presented as "Liabilities Subject to Compromise," in the Consolidated Balance Sheets whereas the carrying value equals the face value. As of the petition date the Company had accrued $24.3 million of interest related to the 2019 notes, reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

2020 Notes. In connection with the consummation of the Combination, on December 16, 2014, the Company assumed $222.1 million in 7½% senior notes due 2020 (the "2020 Notes") originally issued by Forest on September 17, 2012. As of the date of the Combination, the legacy Sabine O&G subsidiaries were added as guarantors to the 2020 Notes, see Note 16 for additional details. Interest on the 2020 Notes is payable semiannually on March 15 and September 15. In conjunction with the consummation of the Combination, the Company recorded the 2020 Notes at a fair value of $104.4 million and recorded a discount of $117.7 million to be amortized over the remaining life of the 2020 Notes utilizing the simple interest method. The remaining unamortized discount was $116.9 million at December 31, 2014. Discount amortization expense was $11.0 million for the year ended December 31, 2015. The remaining unamortized discount of $105.8 million as of the Chapter 11 filing date was expensed as a reorganization item. Due to the amortization of the discount, the effective interest rate on the 2020 Notes is 9.01%.

On May 14, 2015, we received notice that Delaware Trust Company has been appointed as successor trustee under the indenture governing the 2020 Notes.

The Company's filing of the Bankruptcy Petitions constitutes an event of default that accelerated the Company's obligations under the 2020 Notes. However, under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

At December 31, 2014 the 2020 Notes were presented as current liabilities on the Consolidated Balance Sheets whereas the carrying value equaled the face value, net of discount. As of December 31, 2015 the 2020 Notes are presented as "Liabilities Subject to Compromise," in the Consolidated Balance Sheets whereas the carrying value equals the face value. As of the petition date the Company had accrued $5.5 million of interest related to the 2020 notes, reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

Commodity Hedging Activities

Our primary market risk exposure is in the prices we receive for oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot regional market prices applicable to our U.S. natural gas production. Pricing for oil and natural gas 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 depends on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

In the past, we entered into financial commodity derivative contracts to mitigate the potential negative impact on cash flow caused by changes in oil and natural gas prices. However, as a result of certain events of default under our derivative contracts, all our derivative contracts have been terminated. Subsequent to the termination of these derivative contracts, we have not entered into additional derivative contracts. As a result, we no longer have any commodity derivative contracts in place.

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All derivative instruments were recorded at fair market value and are included in the Consolidated Balance Sheets as assets or liabilities. All fair values are adjusted for non-performance risk. For the year ended December 31, 2015, we economically hedged approximately 49% of our combined oil and natural gas volumes, which resulted in operating cash flows from commodity derivative instruments of approximately $92.0 million. For the year ended December 31, 2014, we economically hedged approximately 82% of our combined oil and natural gas volumes, which resulted in operating cash outflows from commodity derivative instruments of approximately $10.8 million. However, we currently have no commodity derivative instruments in place.

Our ability to service our debt obligations and fund our capital expenditures has been negatively impacted by significant decreases in the market price for oil, NGLs and natural gas during the fourth quarter of 2014 with continued weakness through the first quarter 2016. The decrease in the market price for our production directly reduces our operating cash flow. We previously used hedging arrangements to reduce our exposure to fluctuations in the prices of oil, NGLs and natural gas. In addition, the decrease in the market price for our production indirectly impacts our other sources of potential liquidity. Lower market prices for our production may result in lower borrowing capacity under our New Revolving Credit Facility and any replacement thereof or higher borrowing costs from other potential sources of debt financing as our borrowing capacity and borrowing costs are generally related to the value of our estimated proved reserves. As of December 31, 2014, the estimated fair value of all of our commodity derivative instruments was a net asset of $153.3 million which is comprised of current and noncurrent assets and liabilities and as of December 31, 2015 was zero.

The table below summarizes the gains (losses) related to oil and natural gas derivative instruments for years ended December 31, 2015 and 2014:

	Recognized in Other Income (Expenses) For the Year Ended December 31,	
	2015	2014
	(in thousands)	
Cash received (paid) on settlements of derivative instruments	$ 92,042	$ (10,773)
Change in fair value of derivative instruments	(58,145)	132,442
Total gain on derivative instruments	$ 33,897	$ 121,669

Contractual obligations

A summary of our contractual obligations as of December 31, 2015 is provided in the following table.

Payments due by period

For the Year Ending December 31,

	2016 (in millions)	2017	2018	2019	2020	Thereafter	Total
New Revolving Credit Facility (1)	$ 902.1	$ —	$ —	$ —	$ —	$ —	$ 902.1
Term Loan Facility (2)	700.0	—	—	—	—	—	700.0
2017 Senior Notes (2)	350.0	—	—	—	—	—	350.0
2019 Senior Notes (2)	577.9	—	—	—	—	—	577.9
2020 Senior Notes (2)	222.1	—	—	—	—	—	222.1
Office and equipment leases	1.4	0.1	—	—	—	—	1.5
Operating commitments (3)	8.8	9.8	4.7	3.2	2.6	7.4	36.5
Other (4)	14.0	4.3	4.1	4.0	3.8	59.8	90.0
Total	$ 2,776.3	$ 14.2	$ 8.8	$ 7.2	$ 6.4	$ 67.2	$ 2,880.1

(1) Includes outstanding principal amounts that were accelerated during 2015. As of December 31, 2015, the New Revolving Credit Facility is presented as “Liabilities Subject to Compromise” in the Consolidated Balance Sheets, whereas the carrying value equals the face value. Interest expense continues to be recognized and paid on the New Revolving Credit Facility subsequent to the petition date. This table does not include future commitment fees, interest expense or other fees on these facilities because they are floating rate instruments and we cannot determine

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with accuracy the timing of future loan advances, repayments or future interest rates to be charged. As of December 31, 2015, the New Revolving Credit Facility had weighted average interest rates of 4.02%. For more information on the classification of debt, please see Note 2 within “Part II, Item 8. Financial Statements and Supplementary Data.”

(2) As of December 31, 2015, the 2017 Notes, the 2019 Notes, the 2020 Notes and the Term Loan Facility are in default and presented as “Liabilities Subject to Compromise” in the Consolidated Balance Sheets, whereas the carrying value equals the face value. Accrued interest through the petition date was approximately $74.2 million. This amount is not included in this table but is presented within “Liabilities Subject to Compromise” on the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date. For more information on the classification of debt, please see Note 2 within “Part II, Item 8. Financial Statements and Supplementary Data.”

(3) The Company is party to gas and condensate gathering agreements for the transportation and processing of natural gas and condensate for certain properties which provided for contractually obligated annual minimum volume commitments of gas and condensate. Under the terms of the agreements, the Company is required to make annual deficiency payments for any shortfalls in delivering the minimum volumes under these commitments.

(4) Other is comprised primarily of pension and other postretirement benefit obligations, asset retirement obligations and future settlements of deferred service charges, for which neither the ultimate settlement amounts nor the timing of settlement can be precisely determined in advance. See “Critical Accounting Policies, Estimates, Judgments, and Assumptions” below for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

Critical Accounting Policies, Estimates, Judgments, and Assumptions

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities, as well as assets and liabilities reported in purchase price allocations. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. See “Note 3. Significant Accounting Policies” to our Consolidated Financial Statements included herein for an expanded discussion of significant accounting policies and estimates made by management.

Full Cost Method of Accounting

We use the full cost method to account for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and accumulated into a cost center (the amortization base), whether or not the activities to which they apply are successful. This includes any internal costs that are directly related to acquisition, exploration and development activities but does not include any costs associated with production and general corporate activities, which are expensed in the period incurred. The capitalized costs of our oil and natural gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of reserves. Unevaluated costs are excluded from the full cost pool and are periodically considered for impairment. Upon impairment, these costs are transferred to the full cost pool and amortized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is calculated and recognized. The application of the full cost method generally results in higher capitalized costs and higher depletion rates compared to its alternative, the successful efforts method.

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Oil and Gas Reserves Estimates

Our estimates of proved reserves are based on the 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. The accuracy of any reserves estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production and property taxes, development costs, workover costs and abandonment liabilities, all of which may in fact vary considerably from actual results. In addition, as oil, natural gas, and NGL prices that we are required to use pursuant to SEC regulations change from period-to-period, the estimate of proved reserves will also change and the change can be significant. Despite the inherent uncertainty in these engineering estimates, our reserves are used throughout the financial statements. For example, since we use the units-of- production method to amortize oil and natural gas properties, the quantity of reserves could significantly impact DD&A expense. Our oil and natural gas properties are also subject to a ceiling test limitation based in part on the quantity of proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Reference should be made to "Part I, Item 1, Business and Properties" and "Part I, Item 1A, Risk Factors."

Revenue Recognition

We record revenues from the sales of oil, NGLs and natural gas when produced, sold and collectability is ensured. We use the sales method that requires revenue recognition for our net revenue interest of sales from our properties. Accordingly, oil, NGLs and natural gas sales are not recognized for deliveries in excess of our net revenue interest, while oil, NGLs and natural gas sales are recognized for any under delivered volumes. Production imbalances are generally recorded at estimated sales prices of the anticipated future settlements of the imbalances.

Valuation of Deferred Tax Assets

We use the asset and liability method of accounting for income taxes. Under this method, income tax assets and liabilities are determined based on differences between the financial statement carrying values of assets and liabilities and their respective income tax bases (temporary differences). Income tax assets and liabilities are measured using the tax rates expected to be in effect when the temporary differences are likely to reverse. The effect of a change in tax rates on income tax assets and liabilities is included in earnings in the period in which the change is enacted. The book value of income tax assets is limited to the amount of the tax benefit that is more likely than not to be realized in the future.

In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. In making this assessment, we consider the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies, and projected future taxable income. If the ultimate realization of deferred tax assets is dependent upon future book income, assessing the need for, or the sufficiency of, a valuation allowance requires the evaluation of all available evidence, both negative and positive, as to whether it is more likely than not that a deferred tax asset will be realized.

In November 2015, the FASB issued Accounting Standards Update ("ASU") No. 2015-17, Balance Sheet Classification of Deferred Taxes (ASU 2015-17). ASU 2015-17 requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. This is a departure from current guidance, which requires deferred taxes be presented as a net current asset or liability and net noncurrent asset or liability with any valuation allowance allocated on a pro rata basis between current and noncurrent deferred tax assets.

Sabine has elected to early adopt this standard as of 2014. The impact of this will result in netting current and long term deferred tax assets and liabilities and making the previously reported misstatement not effective.

Asset Retirement Obligations

We have obligations to remove tangible equipment and restore locations at the end of the oil and natural gas production operations. Estimating the future restoration and removal costs, or asset retirement obligations (“ARO”), requires us to make estimates and judgments, because most of the obligations are many years in the future, and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs periodically change, as do regulatory, political, environmental, safety, and public relations considerations.

Inherent in the calculation of the present value of our ARO are numerous assumptions and judgments, including the ultimate settlement amounts, 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 present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. Increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense.

Off-Balance Sheet Arrangements

From time to time, we enter into off-balance sheet arrangements and other transactions that can give rise to off-balance sheet obligations. As of December 31, 2015, the off-balance sheet arrangements and other transactions that we have entered into include (i) operating lease agreements, (ii) operating commitments for production and development activities, and (iii) other contractual obligations for which we have recorded estimated liabilities on the balance sheet, but the ultimate settlement amounts are not fixed and determinable, such as derivative contracts, pension and other postretirement benefit obligations, and ARO. We do not believe that any of these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Surety Bonds

In the ordinary course of our business and operations, we are required to post surety bonds from time to time with third parties, including governmental agencies. In addition, while we appeal the arbitration award in Forest Oil Corp., et al. v. El Rucio Land & Cattle Co., et al. (see “Part I, Item 3. Legal Proceedings”), we are required to post a supersedeas bond in the amount of $25 million. As of February 19, 2014, we had obtained this supersedeas bond and were subsequently required by the surety to obtain a letter of credit in the surety’s favor in the amount of $25 million. As of December 31, 2015 the letter of credit was fully drawn. We also have posted surety bonds for a number of bonding institutions covering certain of our current and former operations in the United States in the aggregate amount of approximately $32.6 million which includes the $25 million related to Forest Oil Corp., et al. v. El Rucio Land & Cattle Co., et al.

Non-GAAP Financial Measure

Adjusted EBITDA is a non-GAAP financial measure. We believe the presentation of Adjusted EBITDA provides useful information to investors to evaluate the operations of our business excluding certain items and for the reasons set forth below. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flow operating activities or any other measure of financial performance presented in accordance with US GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

We use Adjusted EBITDA for the following purposes:

- to assess the financial performance of our assets, without regard to financing methods, capital structure or historical cost basis;
- to assess our operating performance and return on capital as compared to those of other companies in the oil and gas industry, without regard to financing or capital structure;
- to assess the viability of acquisition and capital expenditure projects and the overall rates of return on alternative investment opportunities;

· to assess the ability of our assets to generate cash sufficient to pay interest costs and support indebtedness;
· for various purposes, including strategic planning and forecasting;

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Recent Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) No. 2015-17, Balance Sheet Classification of Deferred Taxes (“ASU 2015-17”). ASU 2015-17 requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent in the consolidated balance sheet. Sabine has elected to early adopt this guidance with retrospective presentation as of December 31, 2014. The impact of this resulted in netting current and long term deferred tax assets and liabilities and making the previously reported misstatement not effective.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805) Simplifying the Accounting for Measurement Period Adjustments, eliminating the requirement for the acquirer in a business combination to account for measurement period adjustments retrospectively. ASU 2016-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in this Update require that the acquirer record, in the same period’s financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date recognized. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. Early adoption is permitted. The Company elected to early adopt ASU 2015-16 in the fourth quarter of 2015 and applied the new guidance to the measurement period adjustments recognized during the fourth quarter of 2015. For more information see Note 7.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern (“ASU 2014-15”). ASU 2014-15 provides guidance about management’s responsibility to evaluate whether there is substantial doubt about an entity’s ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. We plan to adopt ASU 2014-15 prospectively for the annual period ending December 31, 2016. Pursuant to ASU 2014-15, the Company is required to consider whether there are adverse conditions or events that raise substantial doubt about the Company’s ability to continue as a going concern within one year after the date that the financial statements are issued and the probability that management’s plans will mitigate the adverse conditions or events (if any). Adverse conditions or events would include, but not be limited to, negative financial trends (such as recurring operating losses, working capital deficiencies, or insufficient liquidity), a need to restructure outstanding debt to avoid default, and industry developments (for example commodity price declines and regulatory changes).

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU 2014-09”), which supersedes nearly all existing revenue recognition guidance under existing US GAAP. This new standards is based upon the principal that revenue is recognized to depict the transfer of 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. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. In July 2015, the FASB elected to defer the effective date of ASU 2014-09 until annual and interim periods beginning after December 15, 2017. Entities have the option of using either a retrospective or modified approach to adopt ASU 2014-09. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.

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Item 8.Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Sabine Oil & Gas Corporation

Houston, Texas

We have audited the accompanying consolidated balance sheets of Sabine Oil & Gas Corporation and subsidiaries (Debtors-in-Possession) (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), shareholders' (deficit) equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sabine Oil & Gas Corporation and subsidiaries (Debtors-in-Possession) as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company has filed for reorganization under Chapter 11 of the United States Bankruptcy Code. The accompanying consolidated financial statements do not purport to reflect or provide for the consequences of the bankruptcy proceedings. In particular, such financial statements do not purport to show (1) as to assets, their realizable value on a liquidation basis or their availability to satisfy liabilities; (2) as to prepetition liabilities, the amounts that may be allowed for claims or contingencies, or the status and priority thereof; (3) as to stockholder accounts, the effect of any changes that may be made in the capitalization of the Company; or (4) as to operations, the effect of any changes that may be made in its business.

The accompanying consolidated financial statements for the years ended December 31, 2015 and 2014 have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code on July 15, 2015. Given the Company's uncertainty surrounding Chapter 11 proceedings, recurring losses from operations and shareholders' deficit, there is substantial doubt about the Company's ability to continue as a going concern. Management's plans concerning these matters are also discussed in Note 2 to the consolidated financial statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 16 to the consolidated financial statements, the condensed consolidating financial information for the years ended December 31, 2014 and 2013 were previously omitted. The current year presentation has been restated to correct this error.

As discussed in Note 6 to the consolidated financial statements, the Company has changed its method of accounting for the classification for deferred taxes in the consolidated balance sheets for the years ended December 31, 2015 and 2014 due to the retrospective adoption of Financial Accounting Standards Board's ("FASB") Accounting Standards Update ("ASU") No. 2015-17, Balance Sheet Classification for Deferred Taxes.

As discussed in Note 4 to the consolidated financial statements, the Company has changed its method of accounting for measurement period adjustments recognized in 2015 due to the early adoption of FASB ASU No. 2015-16, Simplifying the Accounting for Measurement Period Adjustments.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

March 23, 2016

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Consolidated Financial Statements

Sabine Oil & Gas Corporation (Debtors-in-possession)

Consolidated Balance Sheets

As of December 31, 2015 and 2014

	December 31, 2015	December 31, 2014
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 208,637	$ 3,252
Accounts receivable	35,074	108,110
Prepaid expenses and other current assets	9,699	13,092
Derivative instruments	—	160,217
Total current assets	253,410	284,671
Property, plant and equipment:		
Oil and natural gas properties (full cost method)		
Proved	4,730,537	4,214,260
Unproved	—	319,256
Gas gathering and processing equipment	15,811	14,315
Office furniture and fixtures	15,838	14,030
Total property, plant and equipment	4,762,186	4,561,861
Accumulated depletion, depreciation and amortization	(4,253,806)	(2,495,793)
Total property, plant and equipment, net	508,380	2,066,068
Other assets:		
Deferred financing costs, net	—	34,862
Other long-term assets	35,931	6,665
Total other assets	35,931	41,527
Total assets	$ 797,721	$ 2,392,266
Liabilities and shareholders’ deficit		
Current liabilities:		
Accounts payable – trade	$ 11,012	$ 83,282
Royalties payable	15,039	41,368
Accrued exploration and development	6,897	112,580
Accrued operating expenses and other	69,245	71,244
Accrued interest payable	128	30,946
Derivative instruments	—	4,645
Current maturities of long-term debt, net of discount	—	1,988,883
Other short-term liabilities	1,161	14,304
Total current liabilities	103,482	2,347,252

Asset retirement obligation	40,860	39,382
Derivative instruments	—	2,269
Other long-term liabilities	48,197	67,155
Liabilities subject to compromise	2,908,130	—
Total liabilities	3,100,669	2,456,058
Commitments and contingencies (Note 14)		
Shareholders' deficit:		
Preferred stock, $0.01 par value, 10,000,000 authorized shares, 2,508,945 shares issued and outstanding at December 31, 2015 and December 31, 2014	25	25
Common stock, $0.10 par value, 650,000,000 authorized shares; 202,041,900 and 200,975,778 shares issued and outstanding at December 31, 2015 and December 31, 2014, respectively	20,203	20,096
Additional paid in capital	1,566,289	1,564,805
Accumulated deficit	(3,888,361)	(1,648,718)
Other comprehensive loss	(1,104)	—
Total shareholders' deficit	(2,302,948)	(63,792)
Total liabilities and shareholders' deficit	$ 797,721	$ 2,392,266

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

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Consolidated Financial Statements

Sabine Oil & Gas Corporation (Debtors-in-possession)

Consolidated Statements of Operations

For the Years ended December 31, 2015, 2014 and 2013

	For the Year Ended December 31,		
	2015	2014	2013
	(in thousands, except per share amounts)		
Revenues			
Oil, natural gas liquids and natural gas	$ 334,984	$ 462,363	$ 354,223
Other	2,227	2,360	755
Total revenues	337,211	464,723	354,978
Operating expenses			
Lease operating	88,855	51,262	44,620
Marketing, gathering, transportation and other	33,901	23,621	17,567
Production and ad valorem taxes	17,592	18,161	17,824
General and administrative	42,687	30,373	27,469
Depletion, depreciation and amortization	182,417	189,516	137,068
Accretion	1,930	958	952
Impairments	1,576,728	423,092	1,125
Other operating expenses	24,431	25,583	(858)
Total operating expenses	1,968,541	762,566	245,767
Other income (expenses)			
Interest expense, net of capitalized interest (contractual interest expense equals $193,495 year ended December 31, 2015)	(180,285)	(115,559)	(99,448)
Gain on derivative instruments	33,897	121,669	814
Total other income (expenses)	(146,388)	6,110	(98,634)
Reorganization items, net	(458,838)	—	
Net income (loss) before income taxes	(2,236,556)	(291,733)	10,577
Income tax expense	(3,087)	(34,987)	—
Net income (loss)	$ (2,239,643)	$ (326,720)	$ 10,577
Net income (loss) per share:			
Basic	$ (11.17)	$ (2.67)	$ 0.09
Diluted	$ (11.17)	$ (2.67)	$ 0.09
Weighted average shares outstanding – basic	200,513	122,237	118,863
Weighted average shares outstanding – diluted	200,513	122,237	118,863

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

Consolidated Financial Statements

Sabine Oil & Gas Corporation (Debtors-in-possession)

Consolidated Statements of Comprehensive Income (Loss)

For the Years ended December 31, 2015, 2014 and 2013

(in thousands)

	For the Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Net income (loss)	$ (2,239,643)	$ (326,720)	$ 10,577
Other comprehensive loss			
Pension and postretirement benefit plans - net actuarial loss	(1,104)	—	—
Other comprehensive loss	(1,104)	—	—
Comprehensive income (loss)	$ (2,240,747)	$ (326,720)	$ 10,577

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

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Consolidated Financial Statements

Sabine Oil & Gas Corporation (Debtors-in-possession)

Consolidated Statements of Shareholders' (Deficit) Equity

For the Years ended December 31, 2015, 2014 and 2013

(in thousands)

	Preferred Stock		Common Stock		Additional Paid In	Accumulated	Other Comprehensive	Total Shareholders' Equity
	Shares	Value	Shares	Value	Capital	Deficit	Loss	(Deficit)
Balance as of January 1, 2013	—	$ —	118,863	$ 11,885	$ 1,521,123	$ (1,332,575)	$ —	$ 200,433
Distributions	—	—	—	—	(10,000)	—	—	(10,000)
Net income	—	—	—	—	—	10,577	—	10,577
Balance as of December 31, 2013	—	$ —	118,863	$ 11,885	$ 1,511,123	$ (1,321,998)	$ —	$ 201,010
Consideration transferred	—	—	79,242	7,924	32,489	—	—	40,413
Issuance of preferred stock	2,509	25	—	—	(25)	—	—	—
Restricted stock	—	—	2,871	287	(287)	—	—	—
Amortization of stock based compensation	—	—	—	—	1,041	—	—	1,041
Tax effect of transactions with entities under common control	—	—	—	—	20,464	—	—	20,464
Net loss	—	—	—	—	—	(326,720)	—	(326,720)
Balance as of December 31, 2014	2,509	$ 25	200,976	$ 20,096	$ 1,564,805	$ (1,648,718)	$ —	$ (63,792)
Pension and post retirement benefit - net actuarial loss	—	—	—	—	—	—	(1,104)	(1,104)
Restricted stock granted and repurchased	—	—	1,066	107	(288)	—	—	(181)
Amortization of stock based compensation	—	—	—	—	1,772	—	—	1,772

Net loss	—	—	—	—	—	(2,239,643)	—	(2,239,643)
Balance as of December 31, 2015	2,509	$ 25	202,042	$ 20,203	$ 1,566,289	$ (3,888,361)	$ (1,104)	$ (2,302,948)

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

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Consolidated Financial Statements

Sabine Oil & Gas Corporation (Debtors-in-possession)

Consolidated Statements of Cash Flows

For the years ended December 31, 2015, 2014 and 2013

	For the Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Cash flows from operating activities:			
Net income (loss)	$ (2,239,643)	$ (326,720)	$ 10,577
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	182,417	189,516	137,068
Impairments	1,576,728	423,092	1,125
Gain on sale of assets	—	(1,375)	—
Accretion expense	1,930	958	952
Deferred tax expense	3,087	34,987	—
Accrued interest expense and unamortized debt discount	16,667	9,257	10,328
Amortization of deferred financing costs	16,154	11,341	9,587
Non-cash loss (gain) on derivative instruments	62,790	(125,226)	46,545
Amortization of option premiums	(4,645)	(7,216)	(1,171)
Amortization of prepaid expenses	6,770	2,912	4,787
Non-cash stock based compensation	1,772	1,041	—
Other, net	(762)	(72)	(249)
Reorganization items, net	434,800	—	—
Working capital and other changes:			
(Increase) decrease in accounts receivable	85,006	26,286	(38,195)
Increase in other assets	(11,681)	(16,192)	(7,248)
Increase (decrease) in liabilities	3,019	(13,388)	43,092
Net cash provided by operating activities	134,409	209,201	217,198
Cash flows from investing activities:			
Oil and natural gas property additions	(332,771)	(548,841)	(360,080)
Oil and natural gas property acquisitions	—	(36,772)	—
Cash received in Forest acquisition	—	134,887	—
Cash received from insurance proceeds	—	—	604
Gas processing equipment additions	(1,497)	(2,988)	(4,014)
Other asset additions	(1,877)	(2,242)	(2,075)
Cash received from sale of assets	6,749	17,342	171,756
Net cash used in investing activities	(329,396)	(438,614)	(193,809)
Cash flows from financing activities:			

Borrowings under senior secured revolving credit facility	425,987	1,209,835	193,000
Borrowings under second lien term loan	—	—	153,500
Debt repayments for the senior secured revolving credit facility	(24,324)	(969,835)	(348,000)
Debt issuance costs	(1,110)	(19,156)	(6,261)
Shares repurchased	(181)	—	—
Distributions	—	—	(10,000)
Net cash provided by (used in) financing activities	400,372	220,844	(17,761)
Net increase (decrease) in cash and cash equivalents	205,385	(8,569)	5,628
Cash and cash equivalents, beginning of period	3,252	11,821	6,193
Cash and cash equivalents, end of period	$ 208,637	$ 3,252	$ 11,821
Supplemental cash flow information:			
Cash paid for interest, net of interest capitalized	$ 60,073	$ 96,701	$ 76,701
Cash paid for reorganization items	$ 24,038	$ —	$ —
Income tax payments	$ —	$ —	$ —

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

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Sabine Oil & Gas Corporation

Notes to Consolidated Financial Statements

1.Organization

Sabine Oil & Gas Corporation ("Sabine" or the "Company") is an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties in North America. Sabine was incorporated in New York in 1924, as the successor to a company formed in 1916, and has been a publicly held company since 1969.

On December 16, 2014, pursuant to a series of transaction agreements (the "Combination"), certain indirect equity holders (such indirect equity holders are referred to as the "Legacy Sabine Investors") of Sabine Oil & Gas LLC ("Sabine O&G") contributed the equity interests in Sabine O&G to Sabine (which was then known as "Forest Oil Corporation"). In exchange for this contribution, the Legacy Sabine Investors received shares of Sabine common stock and Sabine Series A preferred stock collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine. Holders of Sabine common stock immediately prior to the closing of the Combination continued to hold their Sabine common stock following the closing, which immediately following the closing represented approximately a 26.5% economic interest in Sabine and 60% of the total voting power in Sabine.

On December 19, 2014, the Company filed a certificate of amendment with the New York Secretary of State to change its name from "Forest Oil Corporation" to "Sabine Oil & Gas Corporation."

2.Chapter 11 Proceedings, Liquidity and Ability to Continue as a Going Concern

Voluntary Reorganization Under Chapter 11

On July 15, 2015, the Company and certain of its subsidiaries, including Giant Gas Gathering LLC, Sabine Bear Paw Basin LLC, Sabine East Texas Basin LLC, Sabine Mid-Continent Gathering LLC, Sabine Mid-Continent LLC, Sabine Oil & Gas Finance Corp., Sabine South Texas Gathering LLC, Sabine South Texas LLC and Sabine Williston Basin LLC (collectively, the "Filing Subsidiaries" and, together with the Company, the "Debtors"), filed voluntary petitions (the "Bankruptcy Petitions") for reorganization under the U.S. Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court"). The Debtors' Chapter 11 cases (the "Chapter 11 Cases") are being jointly administered under the case styled In re Sabine Oil & Gas Corporation, et al, No. 15-11835. The Debtors will continue to operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The Company has applied ASC 852, Reorganizations, in preparing its Consolidated Financial Statements.

By certain "first day" motions filed in the Chapter 11 Cases, the Company obtained Bankruptcy Court approval to, among other things and subject to the terms of the orders entered by the Bankruptcy Court pay certain employee wages, health benefits and certain other employee obligations, pay certain lienholders and forward funds to third parties, including royalty holders and other partners, as well as expenses incurred post-petition to these and additional ordinary course creditors.

Appointment of Creditors Committee. On July 28, 2015, The United States Trustee for the Southern District of New York appointed the official committee for unsecured creditors (the "Creditors Committee"). The Creditors Committee and its legal representatives have a right to be heard on all matters that come before the Bankruptcy Court with respect to the Debtors. Disagreements between the Debtors and the Creditors Committee has protracted and will likely continue to protract the Chapter 11 proceedings, potentially negatively impacting the Debtors' ability to operate, and delay the Debtors' emergence from the Chapter 11 proceedings.

Rejection of Executory Contracts. Subject to certain exceptions, under the Bankruptcy Code, the Debtors may assume, assign, or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and certain other conditions. The rejection of an executory contract or unexpired lease is generally treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Debtors of performing their future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Counterparties to such rejected contracts of leases may assert claims against the applicable Debtors' estate for such damages. The assumption of an executory contract or unexpired lease generally requires the Debtors to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with the Debtors in this Annual Report, including where applicable a quantification of our obligations under any such executory contract or unexpired lease with the Debtors, is qualified by any overriding rejection rights we have under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and the Debtors expressly preserve all of their rights with respect thereto.

The Debtors' consolidated financial statements include amounts classified as Liabilities Subject to Compromise (as defined below) that the Debtors believe the Bankruptcy Court will allow as claim amounts resulting from the Debtors' rejection of various executory contracts and unexpired leases and defaults under the debt agreements. Additional amounts may be included in Liabilities Subject to Compromise in future periods if additional executory contracts and unexpired leases are rejected. Conversely, the Debtors expect that the assumption of certain executory contracts and unexpired leases may convert certain liabilities shown in future financial statements as subject to compromise to post-petition liabilities. Due to the uncertain nature of many of the potential claims, the magnitude of such claims is not reasonably estimable at this time. Such claims may be material (see "Liabilities Subject to Compromise" included within Note 4).

Magnitude of Potential Claims. On August 28, 2015, the Debtors filed with the Bankruptcy Court schedules and statements setting forth, among other things, the assets and liabilities of the Debtors, subject to the assumptions filed in connection therewith (the "Schedules and Statements"). The Debtors amended their Schedules and Statements on October 14, 2015, and may subsequently decide to further amend or modify their Schedules and Statements.

Certain holders of pre-petition claims were required to file proofs of claim by the Bar Date. As of February 20, 2016, approximately 1,542 claims totaling approximately $4.97 billion had been filed with the Bankruptcy Court against the Debtors. It is possible that claimants will file amended claims in the future, including claims amended to assign values to claims originally filed with no designated value. Through the claims resolution process, we have identified, and we expect to continue to identify, claims that we believe should be disallowed by the Bankruptcy Court because they are duplicative, have been later amended or superseded, are without merit, are overstated or for other reasons. We will file objections with the Bankruptcy Court as necessary for claims we believe should be disallowed. Claims we believe are allowable are reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets.

Through the claims resolution process, differences in amounts scheduled by the Debtors and claims filed by creditors will be investigated and resolved, including through the filing of objections with the Bankruptcy Court where appropriate. In light of the number of claims filed, the claims resolution process will take additional time to complete, and it may continue after our emergence from bankruptcy. Accordingly, the ultimate number and amount of allowed claims is not presently known, nor can the ultimate recovery with respect to allowed claims be presently ascertained.

Costs of Reorganization. The Debtors have incurred and will continue to incur significant costs associated with the reorganization. The amount of these costs, which are being expensed as incurred, are expected to significantly affect our results of operations. For additional information, see "Reorganization Items, net" below.

Effect of Filing on Creditors and Shareholders. Under the priority scheme established by the Bankruptcy Code, unless creditors agree otherwise, pre-petition liabilities and post-petition liabilities must be satisfied in full before the holders of our existing common stock are entitled to receive any distribution or retain any property under a plan of reorganization. The ultimate recovery to creditors and/or shareholders, if any, will not be determined until confirmation and implementation of a plan or plans of reorganization. No assurance can be given as to what values, if any, will be ascribed in the Chapter 11 proceedings to each of these constituencies or what types or amounts of distributions, if any, they would receive. A plan of reorganization could result in holders of Debtors' liabilities and/or securities, including our common stock, receiving no distribution on account of their interests and cancellation of their holdings. As discussed below, if certain requirements of the Bankruptcy Code are met, a plan of reorganization can be confirmed notwithstanding its rejection by the holders of our common stock and notwithstanding the fact that such holders do not receive or retain any property on account of their equity interests under the plan. Because of such possibilities, the value of our securities, including our common stock, is highly speculative.

Subject to certain exceptions, under the Bankruptcy Code, the filing of the Bankruptcy Petitions automatically enjoined, or stayed, the continuation of most judicial or administrative proceedings or filing of other actions against the Debtors or their property to recover, collect or secure a claim arising prior to the date of the Bankruptcy Petitions. Accordingly, although the filing of the Bankruptcy Petitions triggered defaults on the Debtors' debt obligations, creditors are stayed from taking any actions against the Debtors as a result of such defaults, subject to certain limited exceptions permitted by the Bankruptcy Code. Absent an order of the Bankruptcy Court, substantially all of the Debtors' prepetition liabilities are subject to settlement under the Bankruptcy Code.

Notice and Hearing Procedures for Trading in Claims and Equity Securities. The Bankruptcy Court issued a final order pursuant to Sections 105(a), 362(a) (3) and 541 of the Bankruptcy Code to enable the Debtors to avoid limitations on the use of their tax net operating loss carryforwards and certain other tax attributes by imposing certain notice procedures and transfer restrictions on the trading of our equity securities.

In general, the order applies to any person or entity that, directly or indirectly, beneficially owns (or would beneficially own as a result of a proposed transfer) at least 4.75% of our outstanding equity securities. Substantial Equityholders are required to file with the Bankruptcy Court and serve us with notice of such status. In addition, the order provides that a person or entity that would become a Substantial Equityholder by reason of a proposed acquisition of our equity securities is also required to comply with the notice and service provisions before effecting that transaction. The order gives the Debtors the right to seek an injunction from the Bankruptcy Court to prevent certain acquisitions or sales of our equity securities if the acquisition or sale might adversely affect our ability to utilize such tax attributes.

Under the order, prior to any proposed acquisition of equity securities that would result in an increase in the amount of our equity securities owned by a Substantial Equityholder, or that would result in a person or entity becoming a Substantial Equityholder, such person, entity or Substantial Equityholder is required to file with the Bankruptcy Court, and serve on the Company, a Notice of Intent to Purchase, Acquire or Otherwise Accumulate an Equity Security. In addition, prior to effecting any disposition of our equity securities that would result in a decrease in the amount of our equity securities beneficially owned by a Substantial Equityholder, such Substantial Equityholder is required to file with the Bankruptcy Court, and serve on the Company, a Notice of Intent to Sell, Trade or Otherwise Transfer Equity Securities. Lastly, prior to filing any federal or state tax return or any amendment to such return that claims any deduction for worthlessness regarding our equity securities for a tax year ending before our emergence from Chapter 11, certain shareholders must file with the Bankruptcy Court, and serve on the Company, a Declaration of Intent to Claim a Worthless Stock Deduction, which the Debtors may object to if the claim might adversely affect our ability to utilize our tax attributes.

Any purchase, sale or other transfer of our equity securities in violation of the restrictions of the order would be null and void ab initio as an act in violation of such order and would therefore confer no rights on a proposed transferee.

Plan of Reorganization. A Chapter 11 plan of reorganization, among other things, determines the rights and satisfaction of claims of various creditors and security holders of an entity operating under the protection of the Bankruptcy Court and is subject to the ultimate outcome of stakeholder negotiations and Bankruptcy Court decisions ongoing through the date on which the Chapter 11 plan is confirmed. In order for the Debtors to emerge successfully from the Chapter 11 Cases as reorganized companies, they must obtain approval from the Bankruptcy Court and certain of their respective creditors for a Chapter 11 plan of reorganization. On January 26, 2016, the Debtors filed with the Bankruptcy Court a joint plan of reorganization (the “Plan of Reorganization”) and a related disclosure statement (the “Disclosure Statement”). The Plan of Reorganization, if implemented as proposed by the Debtors, would significantly reduce our outstanding long-term debt and annual interest payments. The Disclosure Statement has not yet been approved by the Bankruptcy Court. Although the Debtors currently have the exclusive right to file a plan and solicit the appropriate votes thereon, such rights expire on February 10, 2016 and April 11, 2016, respectively. Accordingly, the Debtors have filed a motion to further extend their exclusive right to file and solicit acceptance of the Plan of Reorganization, or any other plan, through June 9, 2016 and August 9, 2016, respectively. A hearing on that motion will be held before the US Bankruptcy Court on April 7, 2016 and April 11, 2016. There can be no assurances regarding our ability to successfully develop, confirm or consummate the Plan of Reorganization, an alternative plan or reorganization or another alternative restructuring transactions, including a sale of all or substantially all of our assets, which satisfies the conditions of the Bankruptcy Code and is authorized by the Bankruptcy Court.

In addition to being voted on by holders of impaired claims and equity interests, a plan of reorganization must satisfy certain requirements of the Bankruptcy Code and must be approved, or confirmed, by the Bankruptcy Court in order to become effective. A plan of reorganization would be accepted by holders of claims against and equity interests in the Debtors if (i) at least one-half in number and two-thirds in dollar amount of claims actually voting in each class of claims impaired by the plan have voted to accept the plan and (ii) at least two-thirds in amount of equity interests actually voting in each class of equity interests impaired by the plan has voted to accept the plan. A class of claims or equity interests that does not receive or retain any property under the plan on account of such claims or interests is deemed to have voted to reject the plan.

Under certain circumstances set forth in Section 1129(b) of the Bankruptcy Code, the Bankruptcy Court may confirm a plan even if such plan has not been accepted by all impaired classes of claims and equity interests. The precise requirements and evidentiary showing for confirming a plan notwithstanding its rejection by one or more impaired classes of claims or equity interests depends upon a number of factors, including the status and seniority of the claims or equity interests in the rejecting class (i.e., secured claims or unsecured claims, subordinated or senior claims, preferred or common stock). Generally, with respect to common stock interests, a plan may be “crammed down” even if the shareowners receive no recovery if the proponent of the plan demonstrates that (1) no class junior to the common stock is receiving or retaining property under the plan and (2) no class of claims or interests senior to the common stock is being paid more than in full.

For the duration of the Company’s Chapter 11 proceedings, the Company’s operations and ability to develop and execute its business plan are subject to the risks and uncertainties associated with the Chapter 11 process as described in Item 1A, “Risk Factors.” As a result of these risks and uncertainties, the number of the Company’s outstanding shares and shareholders, assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 proceedings, and the description of the Company’s operations, properties and capital plans included in this Annual Report may not accurately reflect its operations, properties and capital plans following the Chapter 11 process.

Liquidity and Ability to Continue as a Going Concern

The Company’s filing of the Bankruptcy Petitions described above accelerated the Company’s obligations under the New Revolving Credit Facility, the Term Loan Facility, the 2017 Notes and the Legacy Forest Notes. The Company has classified all debt as “Liabilities Subject to Compromise” in the Consolidated Balance Sheets as of December 31, 2015 (see Note 4). If the Company cannot continue as a going concern, adjustments to the carrying values and classification of its assets and liabilities and the reported income and expenses could be required and could be material. For additional description of the defaults present under the Company’s debt obligations, please see Note 8 herein. The Company’s filing of the Bankruptcy Petitions described in Note 2 herein constitutes an event of default that accelerated the Company’s obligations under its debt obligations.

On February 25, 2015, the Company borrowed approximately $356 million under its New Revolving Credit Facility which represented the remaining undrawn amount under the New Revolving Credit Facility. As of December 31, 2015, the Company did not have credit extensions available under the New Revolving Credit Facility due to the going concern qualification in the Company’s 2014 audited financial statements and certain other defaults described below. As of December 31, 2015, the total outstanding principal amount of the Company’s debt obligations was $2.8 billion, consisting of approximately $902 million of borrowings under the New Revolving Credit Facility, $350 million of the

2017 Notes, $800 million of the Legacy Forest Notes, and a $700 million Term Loan Facility. Additionally, the Company’s cash balance at December 31, 2015 was approximately $208.6 million. For additional detail on each of the debt obligations, including definitions of the terms “New Revolving Credit Facility,” “2017 Notes,” “Term Loan Facility” and “Legacy Forest Notes,” please see Note 8 herein.

Events of default, including cross-defaults, are present due to the failure to make interest payments, the failure to make the borrowing base deficiency payments, the “going concern” qualification in the Company’s 2014 audited financial statements and other matters. For additional detail regarding the Company’s other defaults under its debt obligations, please see Note 8 herein.

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We are making adequate protection payments to the lenders under the New Revolving Credit Facility in an amount equal to the non-default rate of interest, fees and costs due and payable on a monthly basis under the New Revolving Credit Facility, in accordance with the cash collateral order filed with the Bankruptcy Court. Additionally, cash generated by the Company deemed to be proceeds of the oil and gas properties that represent prepetition collateral is deposited into a segregated account, which is reflected as Cash in the Consolidated Balance Sheets as of December 31, 2015, and is used solely to pay for the operations of the prepetition collateral properties.

Given uncertainty surrounding Chapter 11 proceedings, recurring losses from operations and shareholders' deficit, there is substantial doubt about our ability to continue as a going concern.

On January 26, 2016, the Debtors filed with the Bankruptcy Court a joint plan of reorganization (the "Plan of Reorganization") for the resolution of the outstanding claims against and interests in the Debtors and a disclosure statement (the "Disclosure Statement") related thereto. The Plan of Reorganization, if implemented as proposed by the Debtors, would significantly reduce our outstanding long-term debt and annual interest payments. The Disclosure Statement has not yet been approved by the Bankruptcy Court. Although the Debtors currently have the exclusive right to file a plan and solicit the appropriate votes thereon, such rights expire on February 10, 2016 and April 11, 2016, respectively. Accordingly, the Debtors have filed a motion to further extend their exclusive right to file and solicit acceptance of the Plan of Reorganization, or any other plan, through June 9, 2016 and August 9, 2016, respectively. A hearing on that motion will be held before the US Bankruptcy Court on April 7, 2016 and April 11, 2016. There can be no assurances regarding our ability to successfully develop, confirm or consummate the Plan of Reorganization, an alternative plan or reorganization or another alternative restructuring transactions, including a sale of all or substantially all of our assets, which satisfies the conditions of the Bankruptcy Code and is authorized by the Bankruptcy Court.

The number of our outstanding shares and shareholders, assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 proceedings.

The consolidated financial statements included in this Annual Report on Form 10-K have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect any adjustments that might result from the outcome of the uncertainties as discussed above.

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3. Immaterial Misstatement

Subsequent to the issuance of the Consolidated Financial Statements for the year ended December 31, 2014, during the preparation of the consolidated financial statements for the quarter ended March 31, 2015 management identified a misstatement in the presentation of deferred taxes associated with its 7¼% senior notes due 2019 (the “2019 Notes”) originally issued by Forest on June 6, 2007, and the 7½% senior notes due 2020 (the “2020 Notes”) originally issued by Forest on September 17, 2012, and the effects of adjusting the allocation of the stepped-up basis in certain assets relating to the effects of the Combination. Such amounts should have been presented as current deferred tax liabilities as of December 31, 2014. The Company also corrected the classification of certain assets related to post-retirement benefit obligations that had previously been presented as “Other short-term assets” on the Consolidated Balance Sheets. Such amounts should have been presented as other long term-assets. Management concluded that these misstatements are immaterial, individually and in the aggregate. The effects of these misstatements on previously reported December 31, 2014 balances are presented in the table below. These balances related to deferred taxes were further adjusted for the impact of adopting ASU No. 2015-17 which reflects zero deferred taxes in the 2014 Consolidated Balance Sheet. Refer to Note 6 for additional details.

	Consolidated Balance Sheet as of December 31, 2014		
	As Previously Reported	Adjustments	As Adjusted for Misstatement
	(in thousands)		
Assets			
Current assets:			
Other short-term assets	$ 8,120	$ (6,565)	$ 1,555
Other assets:			
Deferred income taxes	46,084	71,578	117,662
Other long-term assets	100	6,565	6,665
Total assets	$ 2,438,350	$ 71,578	$ 2,509,928
Liabilities and shareholders’ deficit			
Current liabilities:			
Deferred income taxes	$ 46,084	$ 71,578	$ 117,662
Total liabilities and shareholders’ deficit	$ 2,438,350	$ 71,578	$ 2,509,928

4.Significant Accounting Policies

Basis of Presentation

The Company presents its consolidated financial statements in accordance with U.S. generally accepted accounting principles (“US GAAP”). The accompanying consolidated financial statements include Sabine and its wholly owned subsidiaries. All intercompany transactions have been eliminated.

Sabine O&G is considered the accounting predecessor of Sabine Oil & Gas Corporation. Accordingly, the historical financial information of Sabine Oil & Gas Corporation included in the Consolidated Financial Statements which cover periods prior to the completion of the Combination, reflect the assets, liabilities and operations of Sabine O&G, the accounting predecessor to Sabine Oil & Gas Corporation, and do not reflect the assets, liabilities and operations of Sabine Oil & Gas Corporation. The assets acquired and liabilities assumed in the Combination were recognized in the Consolidated Balance Sheet at their preliminary fair value as of December 16, 2014 and the operating results of the acquired properties are included in the consolidated financial statements for the period beginning thereafter, see Note 7 herein for details of the Combination.

As a result of sustained losses and our Chapter 11 proceedings, the realization of assets and satisfaction of liabilities, without substantial adjustments and/or changes in ownership, are subject to uncertainty. Given uncertainty surrounding Chapter 11 proceedings, there is substantial doubt about our ability to continue as a going concern.

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The accompanying consolidated financial statements do not purport to reflect or provide for the consequences of our Chapter 11 proceedings. In particular, the consolidated financial statements do not purport to show (i) as to assets, their realizable value on a liquidation basis or their availability to satisfy liabilities; (ii) as to pre-petition liabilities, the amounts that may be allowed for claims or contingencies, or the status and priority thereof; (iii) as to shareholders' equity accounts, the effect of any changes that may be made in our capitalization; or (iv) as to operations, the effect of any changes that may be made to our business.

We have applied ASC 852 "Reorganizations," in preparing our consolidated financial statements. ASC 852 requires that the financial statements, for periods subsequent to the Chapter 11 filing, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain revenues, expenses, realized gains and losses and provisions for losses that are realized or incurred in the bankruptcy proceedings are recorded in "Reorganization Items, net" in the accompanying Consolidated Statements of Operations. In addition, pre-petition obligations that may be impacted by the bankruptcy reorganization process have been classified on our Consolidated Balance Sheets at December 31, 2015 in "Liabilities Subject to Compromise". These liabilities include unsecured and under secured obligations which are reported at the amounts expected to be allowed as claims by the Bankruptcy Court, even if they may be settled for lesser amounts.

While operating as debtors in possession under Chapter 11 of the Bankruptcy Code, the U.S. Debtors may sell or otherwise dispose of or liquidate assets or settle liabilities in amounts other than those reflected in our consolidated financial statements, subject to the approval of the Bankruptcy Court or otherwise as permitted in the ordinary course of business.

Liabilities Subject to Compromise

The following table summarizes the components of liabilities subject to compromise (herein referred to as the "Liabilities Subject to Compromise") included in our Consolidated Balance Sheets as of December 31, 2015:

	December 31, 2015 (in thousands)
Accounts payable	$ 23,655
Accrued liabilities	12,108
Accrued interest payable	74,222
Debt	2,752,149
Other short-term liabilities	9,400
Legal and terminated contracts	36,596
Liabilities subject to compromise	$ 2,908,130

Liabilities Subject to Compromise refers to pre-petition obligations that may be impacted by the Chapter 11 reorganization process. The amounts represent our current estimate of known or potential obligations to be resolved in connection with our Chapter 11 proceedings.

Differences between liabilities we have estimated and the claims filed, or to be filed, will be investigated and resolved in connection with the claims resolution process. We will continue to evaluate these liabilities throughout the Chapter 11 process and adjust amounts prospectively as necessary. Such adjustments may be material.

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Reorganization Items, net

The following table summarizes the components included in “Reorganization Items, net” in our Consolidated Statements of Operations for the year ended December 31, 2015:

	For the Year Ended December 31, 2015 (in thousands)
Professional fees	46,117
Deferred financing costs and unamortized discounts	378,705
Terminated contracts	33,197
Interest	(157)
Other	976
Total Reorganization items, net	$ 458,838

The company uses this category to reflect the net revenues, expenses, gains and losses that are the result of the reorganization and restructuring of the business.

Professional fees included in Reorganization items, net represent professional fees for post-petition expenses. Deferred financing costs and unamortized discounts are related to the New Revolving Credit Facility, Term Loan Facility, 2017 Notes, 2019 Notes and 2020 Notes and are included in Reorganization items, net as we believe these debt instruments may be impacted by the bankruptcy reorganization process. Terminated contracts are primarily related to the Company’s rig and servicing contracts rejected on August 10, 2015 by the Court, effective July 15, 2015, as well as other office lease and software agreements. The terminated contracts represent the estimated claims related to rejection of approved contracts that were not previously included in the Consolidated Balance Sheet as the liability was contingent or an executory contract previously reported as commitments and contingencies. Expenses for terminated contracts were based on pre-petition general unsecured claims for damages caused by the Company’s breach of contract.

During the pendency of the bankruptcy proceedings, the Company will operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. ASC 852 applies to entities that have filed a petition for bankruptcy under Chapter 11 of the Bankruptcy Code. The guidance requires that transactions and events directly associated with the reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting and presentation of liabilities, as well as expenses and income directly associated with the Chapter 11 Cases.

Cash and Cash Equivalents

All highly liquid investments purchased with an initial maturity of three months or less are considered to be cash equivalents.

Concentration of Credit Risk

The Company’s significant receivables are comprised of oil and natural gas revenue receivables. The amounts are due from a limited number of entities; therefore, the collectability is dependent upon the general economic conditions of a few purchasers. The Company regularly reviews collectability and establishes the allowance for doubtful accounts as necessary using the specific identification method. The receivables are not collateralized, see Note 4 herein for details.

Oil and Natural Gas Properties and Equipment

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method, the Company capitalizes all acquisition, exploration, and development costs incurred for the purpose of finding oil and natural gas reserves, including salaries, benefits, and other internal costs directly attributable to these activities. The Company capitalized $9.2 million, $10.1 million and $6.6 million of internal costs during the years ended December 31, 2015, 2014 and 2013, respectively. Costs associated with production and general corporate activities are expensed in the period incurred. The Company also includes the present value of its dismantlement, restoration and abandonment costs within the capitalized oil and natural gas property balance (see "Asset Retirement Obligations" below). Unless a significant portion of the Company's proved reserve quantities is sold (greater than 25%), proceeds from the sale of oil and natural gas properties are accounted for as a reduction to capitalized costs, and gains and losses are not recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

Depletion of proved oil and natural gas properties is computed using the units-of-production method based upon estimated proved oil and natural gas reserves. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. Unproved properties are reviewed on a quarterly basis for impairment, and if impaired, are reclassified to proved properties and included in the depletion base.

Under the full cost method of accounting, a ceiling test is performed on a quarterly basis. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test determines a limit on the book value of oil and natural gas properties. The capitalized costs of proved oil and natural gas properties, net of accumulated depletion in the Company's Consolidated Balance Sheets, may not exceed the estimated future net cash flows from proved oil and natural gas reserves, excluding future cash outflows associated with settling asset retirement obligations that have been accrued in the Company's Consolidated Balance Sheets, using the unweighted average first day of the month commodity sales prices for the previous twelve months (adjusted for quality and basis differentials), held constant for the life of production, discounted at 10%, plus the cost of unevaluated properties and major development projects excluded from the costs being amortized. If capitalized costs exceed this limit, the excess is charged to expense and reflected as accumulated depletion.

For the years ended December 31, 2015, 2014 and 2013, the Company recognized an impairment of $1.6 billion, $247.7 million and zero, respectively, for the carrying value of proved oil and natural gas properties in excess of the ceiling limitation. The average of the historical unweighted first day of the month prices for the prior twelve month periods ended December 31, 2015, 2014 and 2013 were $2.58, $4.35 and $3.67, respectively, for natural gas. The average of the historical unweighted first day of the month prices for the prior twelve month periods ended December 31, 2015, 2014 and 2013 were $50.28, $94.99 and $96.78, respectively, for oil.

The Company's depletion expense on oil and natural gas properties is calculated each quarter utilizing period end proved reserve quantities. The Company recorded $178.8 million, $186.8 million and $134.2 million of depletion on oil and natural gas properties for the years ended December 31, 2015, 2014 and 2013, respectively. As a rate of production, depletion was $1.75 per Mcfe, $2.49 per Mcfe and $2.10 per Mcfe for the years ended December 31, 2015, 2014 and 2013, respectively.

Gathering assets and related facilities, certain other property and equipment, and furniture and fixtures are depreciated using the straight-line method based on the estimated useful lives of the respective assets, generally ranging from 3 to 30 years. These assets are tested for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is then recognized if the carrying amount is not recoverable and exceeds fair value. For the years ended December 31, 2015, 2014 and 2013, the Company recorded impairment charges for gas gathering and processing equipment of zero, $1.7 million and zero, respectively, utilized based on expected present value and estimated future cash flows using current volume throughput and pricing assumptions. Leasehold improvements are amortized over the shorter of their economic lives or the lease term. Repairs and maintenance costs are expensed in the period incurred.

Capitalized Interest

The Company capitalizes interest costs to oil and natural gas properties on expenditures made in connection with exploration and development projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. The Company capitalized $3.3 million, $6.5 million and $13.0 million of interest during the years ended December 31, 2015, 2014 and 2013, respectively.

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Derivative Instruments and Hedging Activities

The Company has in the past used derivative financial instruments to achieve a more predictable cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. Such derivative instruments have taken the form of forward contracts, futures contracts, swaps, options, or basis swaps.

During 2015 and 2014, substantially all of Sabine's oil and natural gas derivative contracts were settled based upon reported New York Mercantile Exchange ("NYMEX") prices. The Company's derivative contracts were with multiple counterparties to minimize the Company's exposure to any individual counterparty, and the Company had netting arrangements with all of its counterparties that provide for offsetting payables against receivables from separate hedging arrangements with that counterparty. The oil and natural gas reference prices, upon which the commodity derivative contracts were based, reflect various market indices that have a generally high degree of historical correlation with actual prices received by the Company for its oil and natural gas production. The Company's fixed-price swap and option agreements were used to fix the sales price for the Company's anticipated future oil and natural gas production. Upon settlement, the Company would receive a fixed price for the hedged commodity and receive or pay the counterparty a floating market price, as defined in each instrument. The instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, the Company pays the counterparty. When the fixed price exceeds the floating price, the counterparty is required to make a payment to the Company.

The Company's derivatives instruments utilized in 2015 and 2014 included fixed price oil and natural gas options in addition to fixed price swaps. The Company has bought and sold natural gas puts, bought and sold oil and natural gas calls, sold oil puts and sold oil swaptions in 2014, while in 2013 the Company has bought and sold natural gas puts, bought and sold oil and natural gas calls, and sold oil puts. For the oil and natural gas calls, the counterparty would have the option to purchase a set volume of the contracted commodity at a contracted price on a contracted date in the future. For the oil and natural gas puts, the counterparty would have the option to sell a contracted volume of the commodity at a contracted price on a contracted date in the future.

The Company records balances resulting from commodity risk management activities in the Consolidated Balance Sheets as either assets or liabilities measured at fair value. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented within "Gain on derivative instruments" located in "Other income (expenses)" in the Consolidated Statements of Operations.

Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. Since considerable judgment is required to develop estimates of fair value, the estimates provided are not necessarily indicative of the amounts the Company could realize upon the purchase or refinancing of such instruments. The Company's derivative instruments are reported at fair value based on Level 2 fair value methodologies at December 31, 2014. The New Revolving Credit Facility is carried at face value as of December 31, 2015 and December 31, 2014. The Term Loan Facility, 2017 Notes, 2019 Notes and 2020 Notes are carried at face value as of December 31, 2015 and nominal value, net of unamortized discount as of December 31, 2014. See Note 13 for fair value measurements related to these instruments.

Goodwill

The Company performed an impairment test for goodwill as of December 31, 2014, and recognized $173.5 million impairment of goodwill for the year ended December 31, 2014. No goodwill remained as of December 31, 2014 and 2015.

Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, the Company records an “Asset retirement obligation” (“ARO”) as a liability and capitalizes

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the present value of the asset retirement cost in “Oil and natural gas properties” on the Consolidated Balance Sheets in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation assuming the normal operation of the asset, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the Company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depleted on a unit of production basis within the related full cost pool.

The information below reconciles the recorded amount of the Company’s asset retirement obligations:

	For the Years Ended December 31,	
	2015	2014
	(in thousands)	
Beginning balance	$ 48,782	$ 13,798
Liabilities incurred	468	34,048
Liabilities settled	(920)	(111)
Revisions	—	89
Accretion expense	1,930	958
Reclassification to Liabilities Subject to Compromise	(9,400)	—
Ending balance (1)	$ 40,860	$ 48,782

(1) As of December 31, 2014 Company had AROs of approximately $48.8 million, of which $9.4 million was reported in “Other short-term liabilities” in the Consolidated Balance Sheet attributable to the plugging of abandoned wells.

Revenue Recognition

The Company records revenues from the sales of oil, natural gas liquids and natural gas when produced, sold and collectability is ensured. The Company uses the sales method that requires revenue recognition for the Company’s net revenue interest of sales from its properties. Accordingly, oil, natural gas liquids and natural gas sales are not recognized for deliveries in excess of the Company’s net revenue interest, while oil, natural gas liquids and natural gas sales are recognized for any under delivered volumes. Production imbalances are generally recorded at estimated sales prices of the anticipated future settlements of the imbalances. The Company had no material overproduction or underproduction at December 31, 2015 and 2014.

Use of Estimates

The preparation of the consolidated financial statements for the Company in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

The Company's consolidated financial statements are based on a number of significant estimates, including acquisition purchase price allocations, fair value of derivative instruments, oil, natural gas liquids and natural gas reserve quantities that are the basis for the calculation of DD&A and impairment of oil, natural gas liquids and natural gas properties, assumptions underlying for timing and costs associated with its asset retirement obligations and estimates for certain damages that may be accepted in the Chapter 11 process.

Income Taxes

The Company recognizes deferred tax liabilities and assets for the expected future tax consequences of temporary differences between financial accounting bases and tax bases of assets and liabilities. The tax benefits of tax loss carryforwards and other deferred tax benefits are recorded as an asset to the extent that management assesses the

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utilization of such assets to be more likely than not. When the future realization of some portion of the deferred tax asset is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded deferred tax assets. Refer to Note 6 for details regarding the adoption of ASU 2015-17.

Earnings (Loss) per Share

Basic earnings (loss) per share is computed using the two-class method by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. The two-class method of computing earnings (loss) per share is required to be used because the Company has participating unvested restricted stock granted under the 2014 Long Term Incentive Plan (the "2014 LTIP"). The two-class method is an earnings allocation formula that determines earnings (loss) per share for each class of common stock and participating unvested restricted stock according to dividends declared (or accumulated) and participation rights in undistributed earnings. Holders of restricted stock issued under the Company's 2014 LTIP have the right to receive non-forfeitable dividends if and when declared by the Company, participating on an equal basis with common stock issued and outstanding.

Diluted earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding, increasing the denominator to include the number of additional common shares that would have been outstanding if the dilutive potential common shares (including unvested common shares issued under the 2014 LTIP and additional common shares calculated by assuming that all Series A preferred shares were converted into common shares at the beginning of the period) had been issued. Diluted earnings per share is computed using the more dilutive of the treasury stock method or the two-class method. Under the treasury stock method, the dilutive effect of potential common shares is computed by assuming common shares are issued for these securities at the beginning of the period, with the assumed proceeds from exercise, which include average unamortized stock-based compensation costs, assumed to be used to purchase common shares at the average market price for the period, and the incremental shares (the difference between the number of shares assumed issued and the number of shares assumed purchased) included in the denominator of the diluted earnings per share computation. Under the two-class method, the dilutive effect of non-participating potential common shares is determined and undistributed earnings are reallocated between common shares and participating securities. No potential common shares are included in the computation of any diluted per share amount when a net loss exists because they would be deemed antidilutive, as was the case for the years ended December 31, 2015 and 2014. It was not necessary to include unvested restricted stock grants in the calculations of diluted shares for the year ended December 31, 2013 as grants of restricted stock occurred in 2014, and thus there are no differences between basic and diluted shares in 2013.

Industry Segment and Geographic Information

The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, NGLs and natural gas. The Company considers its gathering, processing and marketing functions as an ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and substantially all of its revenues are attributable to United States customers.

Stock-Based Compensation

The Company accounts for its stock-based compensation including grants of restricted stock and management incentive units in the consolidated statements of operations based on their estimated fair values. The Company recognizes expense on a straight-line basis over the vesting period of the respective grant.

Recent Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2015-17, Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"). ASU 2015-17 requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent in the consolidated balance sheet. Sabine has elected to early adopt this guidance with retrospective presentation as of

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December 31, 2014. The impact of this resulted in netting current and long term deferred tax assets and liabilities and making the previously reported misstatement not effective. See Note 3 for additional details.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805) Simplifying the Accounting for Measurement Period Adjustments, eliminating the requirement for the acquirer in a business combination to account for measurement period adjustments retrospectively. ASU 2016-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in this Update require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date recognized. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. Early adoption is permitted. The Company elected to early adopt ASU 2015-16 in the fourth quarter of 2015 and applied the new guidance to the measurement period adjustments recognized during the fourth quarter of 2015. For more information see Note 7.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. The Company plans to adopt ASU 2014-15 prospectively for the annual period ending December 31, 2016. Pursuant to ASU 2014-15, the Company is required to consider whether there are adverse conditions or events that raise substantial doubt about the Company's ability to continue as a going concern within one year after the date that the financial statements are issued and the probability that management's plans will mitigate the adverse conditions or events (if any). Adverse conditions or events would include, but not be limited to, negative financial trends (such as recurring operating losses, working capital deficiencies, or insufficient liquidity), a need to restructure outstanding debt to avoid default, and industry developments (for example commodity price declines and regulatory changes).

In May 2014, the FASB issued ASU No. 2014 09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under existing generally accepted accounting principles. This new standard is based upon the principal that revenue is recognized to depict the transfer of 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. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. In July 2015, the FASB elected to defer the effective date of ASU 2014-09 until annual and interim periods beginning after December 15, 2017. Entities have the option of using either a retrospective or modified approach to adopt ASU 2014-09. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.

5.Significant Customers

During the year ended December 31, 2015, purchases by three companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Enbridge Pipeline (East Texas) LP, NGL Crude Logistics LLC, and Laclede Energy accounted for approximately 28%, 14%, and 10% of oil, natural gas liquids and natural gas sales, respectively.

During the year ended December 31, 2014, purchases by four companies exceeded 10% of the total oil, natural gas liquids and natural gas sales of the Company. Purchases by Enbridge Pipeline (East Texas) LP, NGL Crude Logistics LLC, Laclede Energy and Eastex Crude Company accounted for approximately 13%, 12%, 12% and 11% of oil, natural gas liquids and natural gas sales, respectively. During the year ended December 31, 2013, purchases by three companies exceeded 10% of the total oil, natural gas liquids and natural gas sales of the Company. Purchases by Eastex Crude Company, Enbridge Pipeline (East Texas) LP and CP Energy LLC accounted for approximately 19%, 16%, and 11% of oil, natural gas liquids and natural gas sales, respectively.

6.Income Taxes

Income Tax Provision

The table below sets forth the provision for income taxes attributable to continuing operations for the periods presented.

	Year Ended December 31, 2015 (In Thousands)	Year Ended December 31, 2014 (In Thousands)	Year Ended December 31, 2013 (In Thousands)
Current:			
Federal	$ —	$ —	$ —
State	—	—	—
Total Current Tax Expense	$ —	$ —	$ —
Deferred:			
Federal	$ 3,043	$ 33,499	$ —
State	44	1,488	—
Total Deferred Tax Expense	$ 3,087	$ 34,987	$ —
Total Income Tax Expense	$ 3,087	$ 34,987	$ —

Prior to its corporate merger, the Company was a partnership and not subject to federal income tax or state income tax (in most states). Accordingly, no provision for federal or state income taxes was recorded prior to the corporate merger as the Company’s equity holders were responsible for income tax on the Company’s profits. In connection with the closing of the merger, the Company merged into a corporation and became subject to federal and state income taxes. The Company’s book and tax basis in assets and liabilities differed at the time of its change in tax status due primarily to different cost recovery periods utilized for book and tax purposes for the Company’s oil and natural gas properties.

At December 31, 2014, the Company recorded a net deferred tax expense of $35.0 million, which includes estimated deferred tax expense of $81.7 million to recognize a deferred tax liability related to the Company’s initial book and tax basis differences from the change in tax status. The deferred tax liability was preliminary and included estimates related to the pre-corporate reorganization period of 2014. Estimates about utilization of tax loss carryforwards obtained through the merger with Forest and tax loss carryforwards generated in the post-corporate reorganization period were also preliminary and reduced the deferred tax impact. The preliminary calculation was based on information available to management at the time such estimates were made.

The Company completed its analysis of the book and tax basis differences with the filing of the corporate income tax return and purchase accounting adjustments. At December 31, 2015, the Company recorded a deferred tax expense of $3.1 million attributable to an increase in the valuation allowance which offsets the additional deferred tax assets recorded through purchase accounting for Forest.

As part of the corporate merger, the Company's historical owners contributed entities that were under common control into Forest. At December 31, 2014, the Company also estimated a net deferred tax asset of $20.5 million related to tax loss carryforwards for these entities. The Company recognized the benefit of the net deferred tax asset in equity. This deferred tax asset was preliminary and based on information available to management at the time the estimate was made. At December 31, 2015, the Company increased the deferred tax asset by $2.1 million to $22.6 million related to tax loss carryforwards for these entities. This increase was a result of a change in estimate and was included in the tax impact recorded in 2015.

At December 31, 2014, the Company's effective tax rate differs from the federal statutory rate of 35% due to earnings prior to the corporate merger that are not subject to corporate income tax, recording the initial book and tax basis differences associated with the change in tax status, state income taxes and impairment of non-deductible goodwill.

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At December 31, 2015, the Company's effective tax rate differs from the federal statutory rate of 35% primarily due to the change in the Company's full valuation allowance recorded against the net deferred tax asset balance, other changes in estimate to post-corporate reorganization period and state income taxes.

The reconciliation of income taxes calculated at the U.S. federal tax statutory rate to the Company's effective tax rate is set forth below:

	Year Ended December 31, 2015 (In Thousands)	Year Ended December 31, 2014 (In Thousands)	Year Ended December 31, 2013 (In Thousands)
Federal income tax at 35% of earnings from continuing operations before income taxes	$ (782,795)	$ (102,107)	$ 3,702
State income taxes, net of federal income tax benefits	(7,422)	(2,131)	—
Earnings not subject to tax	—	(40,509)	(3,702)
Change in non-tax deductible goodwill	—	16,767	—
Change in tax status	—	81,728	—
Change in prior year estimate	3,087		
Other	846	8	—
Change in valuation allowance (current year activity only)	789,371	81,231	—
Total income tax	$ 3,087	$ 34,987	$ —
Effective Tax Rate	(0.14) %	(11.99) %	0.00 %

Net Deferred Tax Assets and Liabilities

On November 20, 2015 the FASB issued ASU 2015-17, "Balance Sheet Classification of Deferred Taxes," as part of the FASB's simplification initiative aimed to reducing complexity in accounting standards. The new guidance requires that all deferred tax assets and liabilities, along with any valuation allowance, be classified as noncurrent on the balance sheet. As a result, each jurisdiction will now only have one net noncurrent deferred tax asset or liability. The new guidance does not change the existing requirements that only permits offsetting within jurisdictions. The new guidance is effective for public business entities in fiscal years beginning after December 15, 2016. However, as early adoption is permitted as of the beginning of an interim or annual reporting period in which the ASU 2015-17 was issued, we decided to apply the new standard for the December 31, 2014 and December 31, 2015 period. As guidance allows for retrospective application of the new standard, prior period financial statements have been retrospectively adjusted. The effects of the application of the new standard on previously reported December 31, 2014 balances in the Form 10-Q for the Quarterly Period ended March 31, 2015 are presented below:

Consolidated Balance Sheet

	as of December 31, 2014	
	As Previously Reported	As Currently Reported
	(in thousands)	
Assets		
Other assets:		
Deferred income taxes	117,662	—
Total assets	$ 2,509,928	$ 2,392,266
Liabilities and shareholders' deficit		
Current liabilities:		
Deferred income taxes	$ 117,662	$ —
Total liabilities and shareholders' deficit	$ 2,509,928	$ 2,392,266

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	Year Ended December 31, 2015	Year Ended December 31, 2014
	(in thousands)	
Deferred tax assets:		
Property and equipment	$ 654,229	$ 279,955
Goodwill	8,630	9,302
Net operating loss carryforwards	353,579	180,134
Liabilities subject to compromise	49,070	—
Other	23,860	48,372
Total gross deferred tax assets	$ 1,089,368	$ 517,763
Less valuation allowance	$ (1,087,637)	$ (344,740)
Net deferred tax assets	$ 1,731	$ 173,023
Deferred tax liabilities:		
Unrealized gains on derivative instruments, net	$ —	$ (27,766)
Long-term liabilities	(52)	(143,259)
Other	(1,679)	(1,998)
Total gross deferred tax liabilities	$ (1,731)	$ (173,023)

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards ("NOLs") at December 31, 2015 were approximately $1,010 million, of which $495 million is subject to limitation under Section 382 of the Internal Revenue Code. The NOL balance excludes NOLs the Company believes the likelihood of utilization to be remote as a result of limitations imposed under Section 382 of the Internal Revenue Code. The NOLs are scheduled to expire in 2019.

The statute of limitations is closed for Sabine's U.S. federal income tax returns for years ending on or before December 31, 2010. The statute of limitations is also closed for Forest's U.S. federal income tax returns for years ending on or before December 31, 2008. However, Forest has utilized, and the Company will continue to utilize, NOLs in its open tax years. The earliest available NOLs were generated in the tax year beginning January 1, 1999, but are potentially subject to adjustment by the federal tax authorities in the tax year in which they are utilized. Thus, the Company's earliest U.S. federal income tax return that is closed to potential audit adjustment is the tax year ending December 31, 1998.

Valuation Allowance

A valuation allowance is established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax asset will not be realized. The Company believes it is more likely than not that the overall deferred tax asset will not be realized. At December 31, 2015, the Company has a valuation allowance of $1,088 million, which is the amount of deferred tax assets that exceed deferred tax liabilities.

Accounting for Uncertainty in Income Taxes

The table below sets forth the reconciliation of the beginning and ending balances of the total amounts of unrecognized tax benefits. The Company records interest and penalty accrual in income tax expense, to the extent they

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apply. The Company does not expect a material amount of unrecognized tax benefits to reverse in the next twelve months. If recognized, none of the uncertain tax positions would impact tax expense.

	Year Ended December 31, 2015 (In Thousands)	Year Ended December 31, 2014 (In Thousands)	Year Ended December 31, 2013 (In Thousands)
Gross unrecognized tax benefits at beginning of period	$ 8,691	$ —	$ —
Increases as a result of tax positions taken during a prior period	—	8,691	—
Decreases as a result of tax positions taken during a prior period	—	—	—
Gross unrecognized tax benefits at end of period	$ 8,691	$ 8,691	$ —

7.Property Acquisitions and Divestitures

The results of the Combination and the acquisitions described below are included in the accompanying Consolidated Statements of Operations since each acquisition's respective close date.

On December 16, 2014, the Legacy Sabine Investors contributed the equity interests in Sabine O&G to Sabine Oil & Gas Corporation, which was then known as "Forest Oil Corporation." In exchange for this contribution, the Legacy Sabine Investors received shares of Sabine common stock and Sabine Series A preferred stock, collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine. Immediately following the contribution, Sabine O&G and related holding companies merged into Forest Oil Corporation ("Forest"), with Forest Oil Corporation surviving the mergers. Holders of Forest common stock immediately prior to the closing of the Combination continued to hold their common stock following the closing, which immediately following the closing represented approximately a 26.5% economic interest in Sabine and 60% of the total voting power in Sabine. On December 19, 2014, Forest Oil Corporation changed its name to "Sabine Oil & Gas Corporation." Sabine Oil & Gas LLC was the accounting acquirer in the Combination. The business purpose for the Combination was to combine Forest and Sabine O&G's complementary asset portfolios to create a larger company that would benefit from drilling optimization and economies of scale.

Calculation of Consideration Transferred

The following details the fair value of consideration used to effect the Combination:

Number of shares of Forest Oil Corporation outstanding as of the date of the Combination (in thousands)	118,863
Forest Oil Corporation closing stock price on December 16, 2014	$ 0.34

Common stock equity consideration (in thousands)	$ 40,413

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Allocation of Consideration Transferred to Net Assets Acquired

The following amounts represent the estimates of the fair value of identifiable assets acquired and liabilities assumed in the Combination.

(Stated in thousands of dollars)	December 16, 2014 (as previously reported)	Adjustments (1)	December 16, 2014 (as adjusted)
Cash	134,887		134,887
Accounts receivable	61,889	5,908	67,797
Prepaid expenses and other current assets	7,225	(523)	6,702
Derivative instruments	31,621		31,621
Oil and natural gas properties, proved	343,127		343,127
Oil and natural gas properties, unproved	189,877	(17,499)	172,378
Other long term assets	8,121	3	8,124
Other fixed assets	697	20	717
Net deferred tax asset	14,524	3,087	17,611
Accounts payable	(76,766)	(1,908)	(78,674)
Royalties payable	(7,446)	(110)	(7,555)
Accrued exploration and development	(27,982)	211	(27,771)
Accrued operating expense and other	(29,246)	(12)	(29,258)
Accrued interest	(4,730)		(4,730)
Other short-term obligations (2)	(15,191)		(15,191)
Revolving credit facility	(105,000)		(105,000)
Senior notes	(394,783)		(394,783)
Asset retirement obligations	(23,946)		(23,946)
Other long-term obligations	(66,465)	10,823	(55,643)
Total identifiable net assets and consideration transferred	$ 40,413	$ —	$ 40,413

(1) Adjustments to the fair value of identifiable assets acquired and liabilities assumed in the Combination are related to a change in the estimated fair value of unproved properties, a change in the fair value of other long term obligations as a result of curtailments in the post retirement benefit plans and a change in estimate or classification of other assets and liabilities. These adjustments were primarily recorded at the end of the measurement period, which was considered to be December 16, 2015.

(2) Includes $9.4 million of asset retirement obligations.

All assets and liabilities including oil and gas properties were recorded at their fair value. In determining the fair value of the oil and gas properties, the Company prepared estimates of oil and natural gas reserves. The Company used estimated future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at the estimates of future net revenues. The valuations to derive the purchase price included the use of both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates. Other significant estimates were used by management to calculate fair value of assets acquired and liabilities assumed. Certain adjustments were made during the measurement period process as outlined above.

The actual impact of the Combination was an increase to "Total revenues" in the Consolidated Statement of Operations of $7.8 million for the year ended December 31, 2014 and a decrease to "Net loss" in the consolidated Statement of Operations of $5.3 million for the year ended December 31, 2014. The unaudited pro forma results presented below have been prepared to give the effect of the acquisition discussed above on our results of operations for the years ended December 31, 2014 and 2013 as if it had been consummated on January 1, 2013. The unaudited pro

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forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on such date or to project our results of operations for any future date or period.

	For the Year Ended December 31, 2014		For the Year Ended December 31, 2013	
	Actual (in thousands)	Pro forma	Actual (in thousands)	Pro forma
Pro forma (unaudited)				
Total revenues	$ 464,723	$ 673,641	$ 354,978	$ 518,167
Net income (loss)	(326,720)	(286,052)	10,577	(8,226)

On June 10, 2014 and March 25, 2014, the Company acquired working interests in certain oil and natural gas properties in North Texas for a total of $38.0 million, net of purchase price adjustments. The Company recorded a fair value of $33.4 million for proved properties and $4.6 million for unproved properties. No material ARO liability was assumed. The valuations to derive the purchase price included both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, risk adjusted discount rates and fair value of unevaluated leaseholds.

The total pro forma impact of the June 10, 2014 and March 25, 2014 acquisitions was an increase to “Total revenues” on the Consolidated Statement of Operations of $4.0 million for the year ended December 31, 2014, and an increase to “Net loss” on the Consolidated Statement of Operations of $2.4 million for the year ended December 31, 2014.

On December 18, 2013, the Company closed on the sale of its interests in certain oil and natural gas properties in the Texas Panhandle and surrounding Oklahoma area for $169.0 million, net of certain purchase price adjustments. The sale of the Texas Panhandle and surrounding Oklahoma properties was accounted for as an adjustment to the full cost pool with no gain or loss recognized. Subsequent to December 31, 2013, the Company has recorded purchase price adjustments of approximately $8.4 million in additional proceeds as a result of clearing title defects and adjusting post effective date estimates.

On April 30, 2013, Sabine closed on the purchase of interests in approximately 5,000 net acres in South Texas for approximately $14.9 million. The acquisition does not qualify as a business combination because the assets acquired do not meet the definition of a business.

Acquired properties that are considered to be business combinations are recorded at their fair value. In determining the fair value of the properties, the Company prepares estimates of oil and natural gas reserves. The Company uses estimated future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at the estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. To compensate for inherent risks of estimating and valuing reserves, proved undeveloped, probable and possible reserves are reduced by additional risk-weighting factors.

8.Debt
Senior Notes
2017 Notes

The Company and the Company’s subsidiary Sabine Oil & Gas Finance Corporation, formerly NFR Energy Finance Corporation, have $350 million in 9.75% senior unsecured notes due 2017 (the “2017 Notes”) currently outstanding. The 2017 Notes are unsecured obligations that bear interest at a rate of 9.75% per annum, payable semi-annually on February 15 and August 15 each year. In conjunction with the issuance of the 2017 Notes, the Company recorded a discount to be amortized over the remaining life of the 2015 Notes utilizing the simple interest method. The remaining unamortized discount was $1.4 million at December 31, 2014. Discount amortization expense was $0.3 million for the year ended

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December 31, 2015. The remaining unamortized discount of $1.1 million as of the Chapter 11 filing date was expensed as a reorganization item. The 2017 Notes were issued under, and are governed by, an indenture dated February 12, 2010 by and among Sabine Oil & Gas Corporation, Sabine Oil & Gas Finance Corporation, the Bank of New York Mellon Trust Company, N.A. as trustee, and guarantors party thereto. Due to the amortization of the discount, the effective interest rate on the 2017 Notes was 5.57%. The Company's filing of the Bankruptcy Petitions described in Note 2 herein constitutes an event of default that accelerated the Company's obligations under the 2017 Notes.

At December 31, 2014, the 2017 Notes were presented as current liabilities in the Consolidated Balance Sheets whereas the carrying value equaled the face value, net of discount. As of December 31, 2015 the 2017 Notes are presented as "Liabilities Subject to Compromise" in the Consolidated Balance Sheet, whereas the carrying value equals the face value. As of the petition date, the Company had accrued $14.1 million of interest related to the 2017 Notes, reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

2019 Notes

In connection with the consummation of the Combination, on December 16, 2014, the Company assumed $577.9 million in 7¼% senior notes due 2019 (the "2019 Notes") originally issued by Forest on June 6, 2007. As of the date of the Combination, the legacy Sabine O&G Subsidiaries were added as guarantors to the 2019 Notes, see Note 16 herein for additional details. Interest on the 2019 Notes is payable semiannually on June 15 and December 15. In conjunction with the consummation of the Combination, the Company recorded a discount of $287.5 million to be amortized over the remaining life of the 2019 Notes utilizing the simple interest method. The remaining unamortized discount was $284.9 million at December 31, 2014. Discount amortization expense was $34.4 million for the year ended December 31, 2015. The remaining unamortized discount of $250.4 million as of the Chapter 11 filing date was expensed as a reorganization item. Due to the amortization of the discount, the effective interest rate on the 2019 Notes for the year ended December 31, 2015 was 9.86%.

At December 31, 2014, the 2019 Notes were presented as current liabilities in the Consolidated Balance Sheets whereas the carrying value equaled the face value net of discount. As of December 31, 2015, the 2019 Notes are presented as "Liabilities Subject to Compromise" in the Consolidated Balance Sheets, whereas the carrying value equals the face value. As of the petition date the Company had accrued $24.3 million of interest related to the 2019 notes, reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

On February 25, 2015, the Company received notice that Wilmington Savings Fund Society, FSB has been appointed as successor trustee under the indenture governing the 2019 Notes. The Company's filing of the Bankruptcy Petitions described in Note 2 herein constitutes an event of default that accelerated the Company's obligations under the 2019 Notes.

Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

2020 Notes

In connection with the consummation of the Combination, on December 16, 2014, the Company assumed $222.1 million in 7½% senior notes due 2020 (the "2020 Notes") originally issued by Forest on September 17, 2012. As of the date of the Combination, the legacy Sabine O&G subsidiaries were added as guarantors to the 2020 Notes, see Note 16 herein for additional details. Interest on the 2020 Notes is payable semiannually on March 15 and September 15. In conjunction with the consummation of the Combination, the Company recorded a discount of $117.7 million to be amortized over the remaining life of the 2020 Notes utilizing the simple interest method. The remaining unamortized discount was $116.9 million at December 31, 2014. Discount amortization expense was $11.0 million for the year ended

December 31, 2015, respectively. The remaining unamortized discount of $105.8 million as of the Chapter 11 filing date was expensed as a reorganization item. Due to the amortization of the discount, the effective interest rate on the 2020 Notes for the year ended December 31, 2015 was 9.01%.

At December 31, 2014, the 2020 Notes were presented as current liabilities in the Consolidated Balance Sheets whereas the carrying value equaled the face value, net of discount. As of December 31, 2015, the 2020 Notes are presented as “Liabilities Subject to Compromise” in the Consolidated Balance Sheets, whereas the carrying value equals the face value. As of the petition date the Company had accrued $5.5 million of interest related to the 2020 notes, reflected in “Liabilities Subject to Compromise” in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

On May 14, 2015, the Company received notice that Delaware Trust Company has been appointed as successor trustee under the indenture governing the 2020 Notes. The Company’s filing of the Bankruptcy Petitions described in Note 2 herein constitutes an event of default that accelerated the Company’s obligations under the 2020 Notes.

Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

The New Revolving Credit Facility

On November 30, 2007, the Company entered into a senior secured revolving credit facility (the “Former Revolving Credit Facility”) with a syndicate of banks. Through a series of redeterminations, the Company has amended and restated the Credit Facility, with a maturity date of April 7, 2016. The most recent redetermination effective November 12, 2014, increased the borrowing base from $700 million to $750 million. On December 16, 2014, in connection with the consummation of the Combination, the Company amended and restated the Amended and Restated Credit Agreement, dated as of April 28, 2009, by and among Sabine O&G, Wells Fargo Bank, National Association, as administrative agent, and the lenders and other parties party thereto (the “Former Revolving Credit Facility”) with the Second Amended and Restated Credit Agreement (the “New Revolving Credit Facility”). The New Revolving Credit Facility provides for a $2 billion revolving credit facility, with an initial borrowing base of $1 billion. The New Revolving Credit Facility includes a sub-limit permitting up to $100 million of letters of credit. On April 27, 2015 the borrowing base for the New Revolving Credit Facility was reduced to $750 million. The New Revolving Credit Facility matures on April 7, 2016; however, as a result of the filing of the Bankruptcy Petitions, the obligations have been accelerated and are subject to the Bankruptcy Court automatic stay.

On May 4, 2015, the Company entered into a Forbearance Agreement and First Amendment (the “NRCF Forbearance Agreement”) to the New Revolving Credit Facility to address certain events of default that were present. Pursuant to the NRCF Forbearance Agreement, the lenders agreed to forbear from exercising remedies until the earlier of (i) certain events of default under the NRCF Forbearance Agreement or the New Revolving Credit Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) June 30, 2015 (the “Initial NRCF Forbearance Period”), with respect to the following anticipated (at the time) events of default: (i) the “going concern” qualification in the Company’s 2014 audited financial statements, (ii) the failure of the Company to make the April 2015 interest payment due under the Term Loan Facility, and (iii) any failure of the Company to make the May 27, 2015 and June 27, 2015 borrowing base deficiency payments under the New Revolving Credit Facility. In exchange for the lenders agreeing to forbear, the Company agreed during the Initial NRCF Forbearance Period to, among other things, tighten certain covenants under the New Revolving Credit Facility and provide mortgages on certain currently unencumbered properties.

On June 30, 2015, the Company entered into an Amendment (the "NRCF Forbearance Amendment") to the NRCF Forbearance Agreement. Pursuant to the NRCF Forbearance Amendment, the lenders agreed to forbear from exercising remedies until the earlier of (i) certain events of default under the NRCF Forbearance Agreement or New Revolving Credit Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) July 15, 2015 (the "Second Forbearance Period"), with respect to the Company's currently existing events of default under the New Revolving Credit Facility. In exchange for the lenders agreeing to forbear, the Company agreed during the Second Forbearance Period to (i) further limit its ability to sell assets, (ii) undertake efforts to appoint a chief restructuring officer, (iii) implement procedures to segregate the proceeds of collateral under the New Revolving Credit Facility and (iv) pay a forbearance fee equal to $500,000.

The Company's filing of the Bankruptcy Petitions described in Note 2 herein constituted an event of default that accelerated the Company's obligations under the New Revolving Credit Facility. Additionally other events of default, including cross-defaults, are present due to the failure to make interest payments, the failure to make the borrowing base deficiency payments, the "going concern" qualification in the Company's 2014 audited financial statements and other matters.

Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Debtors as a result of the default.

The Company is making adequate protection payments to the lenders under the New Revolving Credit Facility in an amount equal to the non-default rate of interest, fees and costs due and payable on a monthly basis under the New Revolving Credit Facility, in accordance with the cash collateral order filed with the Bankruptcy Court. Additionally, cash generated by the Company deemed to be proceeds of the oil and gas properties that represent prepetition collateral is deposited into a segregated account, which is reflected as Cash in the Consolidated Balance Sheet as of December 31, 2015, and is used solely to pay for the operations of the prepetition collateral properties.

Prior to May 29, 2015, loans under the New Revolving Credit Facility bore interest at the Company's option at either:

- the sum of (1) the Alternate Base Rate, which is defined as the highest of (a) Wells Fargo Bank, National Association's prime rate; (b) the federal funds effective rate plus 0.50%; or (c) the Eurodollar Rate (as defined in the New Revolving Credit Facility) for a one-month interest period plus 1% and (2) a margin varying from 0.50% to 1.50% depending on the Company's most recent borrowing base utilization percentage; or
- the Eurodollar Rate plus a margin varying from 1.50% to 2.50% depending on the Company's most recent borrowing base utilization percentage.

Beginning in May 29, 2015 and thereafter during the occurrence of an event of default under the New Revolving Credit Facility, the loans under the New Revolving Credit Facility will bear interest at the Revolving Base Rate (as defined in the New Revolving Credit Facility).

As of December 31, 2015 and 2014, borrowings outstanding under the New Revolving Credit Facility and the Former Revolving Credit Facility totaled $902 million and $545 million, respectively, and there were zero and $29 million of outstanding letters of credit, respectively. Additionally, borrowings outstanding under the New Revolving Credit Facility had a weighted average interest rate of 4.0% and 2.4% for the twelve months ended December 31, 2015 and 2014.

The New Revolving Credit Facility provides that all such obligations and the guarantees will be secured by a lien on at least 80% of the PV-9 of the borrowing base properties evaluated in the most recent reserve report delivered to the administrative agent and a pledge of all of the capital stock of the Company's restricted subsidiaries, subject to certain customary grace periods and exceptions.

At December 31, 2014 the New Revolving Credit Facility was presented as a current liability in the Consolidated Balance Sheets whereas the carrying value equaled the face value. As of December 31, 2015 the New Revolving Credit Facility is presented as "Liabilities Subject to Compromise," whereas the carrying value equals the face value. Interest expense continues to be recognized on the New Revolving Credit Facility subsequent to the petition date.

Term Loan Facility

Sabine O&G entered into a $500 million second lien term loan agreement (“Term Loan Facility”) on December 14, 2012 with a maturity date of December 31, 2018 (provided that if the 2017 Senior Notes were not refinanced to mature at

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least 91 days thereafter, the maturity date would be 91 days prior to the February 15, 2017 maturity date of the 2017 Senior Notes). On January 23, 2013, the syndication was completed with an additional funding of $150 million of proceeds pursuant to the first amendment to the Term Loan Facility bringing the outstanding balance to $650 million as of December 31, 2013. Proceeds from the Term Loan Facility were used to acquire oil and natural gas properties in December 2012 and repay borrowings under the former revolving credit facility in the first quarter of 2013.

In connection with the consummation of the Combination, on December 16, 2014, the Company entered into an amendment to the Term Loan Facility to provide for $50 million of incremental term loans (the "Incremental Term Loans"). The Incremental Term Loans are fungible with the existing $650 million of second lien loans under the Term Loan Facility, including with respect to interest and, in the case of eurodollar borrowings, they bear interest at the Adjusted Eurodollar Rate (as defined in the Term Loan Facility) plus 7.50%, with an interest rate floor of 1.25%, and, in the case of alternate base rate borrowings, they bear interest at the Alternate Base Rate (as defined in the Term Loan Facility) plus 6.50%, with an interest rate floor of 2.25%. Any time an interest period for loans expires during an event of default under the Term Loan Facility, such loans will bear interest at the Term Base Rate (as defined in the Term Loan Facility). The weighted average interest rate incurred on this indebtedness for the years ended December 31, 2015 and 2014 was 5.32% and 8.8%, respectively.

On May 20, 2015, the Company entered into a Forbearance Agreement and Third Amendment (the "Term Loan Forbearance Agreement") to the Term Loan Facility. Pursuant to the Term Loan Forbearance Agreement, the lenders under the Term Loan Facility agreed to forbear from exercising remedies until the earlier of (i) certain events of default under the Term Loan Forbearance Agreement or Term Loan Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) June 30, 2015 (the "Initial Term Loan Forbearance Period"), with respect to the following anticipated (at the time) events of default: (i) the "going concern" qualification in the Company's 2014 audited financial statements and (ii) the failure of the Company to make the April 2015 interest payment due under the Term Loan Facility. In exchange for the lenders under the Term Loan Facility agreeing to forbear, the Company has agreed during the Initial Term Loan Forbearance Period to, among other things, tighten certain covenants under the Term Loan Facility.

On July 8, 2015, the Company entered into an Amendment (the "Term Loan Forbearance Amendment") to the Term Loan Forbearance Agreement. Pursuant to the Term Loan Forbearance Amendment, the lenders agreed to forbear from exercising remedies until the earlier of (i) certain events of default under the Term Loan Forbearance Agreement or Term Loan Facility, (ii) the acceleration or exercise of remedies by any other lender or creditor, and (iii) the earlier of the termination of the forbearance period under the New Revolving Credit Facility and July 15, 2015 (the "Second Term Loan Forbearance Period"), with respect to the Company's then currently existing events of default under the Term Loan Facility. In exchange for the lenders agreeing to forbear, the Company agreed during the Second Term Loan Forbearance Period to, among other things, tighten certain covenants under the Term Loan Facility.

The Company's filing of the Bankruptcy Petitions described above in Note 2 constituted an event of default that accelerated the Company's obligations under the Term Loan Facility. Additionally other events of default are present due to the failure to make interest payments, the "going concern" qualification in the Company's 2014 audited financial statements and other matters.

At December 31, 2014 the Term Loan Facility was presented as a current liability in the Consolidated Balance Sheets whereas the carrying value equaled the face value, net of discount. As of December 31, 2015 the Term Loan Facility is presented as "Liabilities Subject to Compromise" in the Consolidated Balance Sheets, whereas the carrying value equals the face value. As of the petition date the Company had accrued $30.2 million of interest related to the Term Loan Facility, reflected in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets. No interest expense has been recognized subsequent to the petition date.

All of the Company's guarantees for its New Revolving Credit Facility have guaranteed the Term Loan Facility. The obligations under the Term Loan Facility are secured by the same collateral that secures the New Revolving Credit Facility, but the liens securing such obligations are second priority liens to the liens securing the New Revolving Credit Facility. However, the validity of certain liens securing the Term Loan Facility are currently in dispute pursuant to the lawsuit filed by the Company against the Term Loan Facility administrative agent, Wilmington Trust, N.A.

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9.Shareholders' (Deficit) Equity

Common Stock

At December 31, 2013, Sabine O&G was authorized to issue one class of units to be designated as "Common Units". The units were not represented by certificates. All Common Units were issued at a price equal to $1,000 per unit. In the year ended December 31, 2013, Sabine O&G made a one-time payment to Nabors Industries LTD "Nabors" in the amount of $10 million in order to satisfy commitments to Nabors that were otherwise guaranteed by First Reserve.

On December 16, 2014, in connection with the Combination, certain indirect equity holders of Sabine O&G contributed the equity interests in Sabine O&G to Sabine. In exchange for this contribution, the equity holders of Sabine O&G received approximately 79.2 million shares of Sabine common stock (the "Common Shares") and approximately 2.5 million Series A senior non-voting preferred stock ("Series A Preferred Shares"; see "—Preferred Stock" below) collectively representing approximately a 73.5% economic interest in Sabine and 40% of the total voting power in Sabine.

Holders of Forest common stock immediately prior to the closing of the Combination continued to hold their common stock following the closing of the Combination representing approximately a 26.5% economic interest in Sabine and 60% of the total voting power in Sabine. Common Shares of Sabine held by the holders of Forest common stock is 118.9 million shares.

Additionally, approximately 16.9 million shares and approximately 0.7 million shares of service-based restricted stock were awarded subsequent to the consummation of the Combination in 2014 and in the three months ended March 31, 2015, respectively. No additional shares of service-based restricted stock were awarded in the second, third and fourth quarters of 2015. Refer to Note 10.

At December 31, 2015, the Company had 650.0 million Common Shares, par value $0.10 per share, authorized and 202.0 million shares issued and outstanding.

Earnings per share and share information presented in the consolidated financial statements for periods prior to December 16, 2014 are based on the Company's common shares calculated by multiplying the number of Sabine O&G's units outstanding at the end of each period using an exchange ratio as derived from the agreement governing the Combination. The Company retroactively adjusted its Statement of Shareholders' (Deficit) Equity at the end of each period using an exchange ratio as derived from the agreement governing the Combination to reflect the legal capital of the accounting acquiree. Beginning on December 16, 2014 common shares are presented for the combined company.

The Company has a significant amount of indebtedness that is senior to its existing common stock in its capital structure. As a result, the Company believes that it is highly likely that the shares of its existing common stock will be cancelled in its Chapter 11 proceedings and will be entitled to a limited recovery, if any. Additionally, as a result of the filing of the Bankruptcy Petitions, the Company's common stock can no longer be traded on the OTCQB Marketplace and is now trading on the OTC Pink Marketplace.

Preferred Stock

On December 16, 2014, in connection with the Combination, certain indirect equity holders of Sabine O&G received 2.5 million Series A Preferred Shares.

The Series A Preferred Shares are convertible into Sabine Common Shares at the option of certain indirect equity holders of Sabine O&G if (1) the indirect equity holders of Sabine O&G are able to convert a portion of the Series A

Preferred Shares into Common Shares and, as a result of such conversion, would not, together with affiliates, hold more than 50% of the Company’s voting power and (2) Sabine’s board of directors (the “Board”) approves such conversion (such approval not to be unreasonably withheld). In addition, Series A Preferred Shares will convert automatically if the indirect equity holders of Sabine O&G transfer such shares to a third party and such third party would not, together with its affiliates, hold more than 50% of the Company’s voting power upon receipt of such shares as voting securities.

The Series A Preferred Shares are non-voting. Initially, in connection with a conversion of Series A Preferred Shares into Common Shares as described in the preceding paragraph, each Series A Preferred Share will be convertible into 100 Common Shares.

At December 31, 2015, the Company had 10.0 million Series A Preferred Shares, par value $0.01, authorized and 2.5 million shares issued and outstanding.

The Company has a significant amount of indebtedness that is senior to its existing preferred stock in its capital structure. As a result, the Company believes that it is highly likely that the shares of its existing preferred stock will be cancelled in its Chapter 11 proceedings and will be entitled to a limited recovery, if any.

Incentive Units

The Incentive Units were issued pursuant to the Combination in exchange for Incentive Units that were outstanding prior to the Combination, and were amended in connection with the closing of the Combination. The Incentive Units that were outstanding prior to the Combination were not a substantive class of equity and participated only upon liquidation events meeting certain requisite financial thresholds which were not considered probable, and, as such, were considered to be liability-based awards with no fair value recognized as of December 31, 2013. As amended, the Incentive Units represent the equivalent of stock appreciation rights redeemable for an applicable number of common shares of the Company (based on the value of the common shares). As such, the Incentive Units as amended in connection with the Combination were considered to be equity-based awards with a grant date fair value of approximately $2.1 million, of which compensation expense will be recognized on a straight line basis over the requisite service period. The compensation expense recognized in the year ended December 31, 2015 was $0.4 million.

The Company has a significant amount of indebtedness that is senior to its existing incentive units in its capital structure. As a result, the Company believes that it is highly likely that the shares of its existing incentive units will be cancelled in its Chapter 11 proceedings and will be entitled to a limited recovery, if any.

10.Stock-Based Compensation

Description of plan

In November 2014, the Company adopted the 2014 LTIP under which nonstatutory options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, and other stock-based awards may be granted to employees, directors and consultants of the Company. The aggregate number of shares of common stock that the Company may issue under the 2014 LTIP may not exceed 20 million shares. On December 16, 2014, in connection with the closing of the Combination, subject to the approval of the Sabine shareholders, the board of directors of Sabine voted to amend the 2014 LTIP to increase the total number of Common Shares reserved for issuance in connection with awards under the 2014 LTIP from 20 million to 40 million, effective as of the date of such shareholder approval. As of December 31, 2015, the Company had 4.3 million shares available for issuance under the 2014 LTIP. During 2015, 2014 and 2013, the Company recognized approximately $1.3 million, $1.0 million and zero, respectively, in stock based compensation expense which is included in General and Administrative expense in the Consolidated Statement of Operations.

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Restricted stock

The following table summarizes the restricted stock activity in the 2014 LTIP for the year ended December 31, 2015.

	Restricted Stock Awards Weighted		
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares Remaining Available for Future Issuance under 2014 LTIP
Unvested at December 31, 2014	13,923,230	$ 0.34	3,205,597
Awarded	719,132	0.24	(719,132)
Vested	(2,727,871)	0.34	—
Forfeited	(1,815,200)	0.34	1,815,200
Unvested at December 31, 2015	10,099,291	0.33	4,301,665

The grant date fair value of restricted stock is determined by averaging the high and low stock price of a share of Sabine common stock as published by the OTC Bulletin Board on the date of grant. Of the unvested restricted stock as of December 31, 2015, 8,779,037 shares vest as follows: (i) two-thirds will vest in one-fourth increments on each of the first four anniversaries of the date of grant and (ii) one-third will vest in full on the fourth anniversary of the date of grant; 720,254 shares vest ratably over three years; and 600,000 shares vest ratably over four years. Restricted stock may vest earlier upon a qualifying disability, death, certain involuntary terminations, or a change in control of the Company in accordance with the terms of the underlying agreement.

11.Statement of Cash Flows

The Company paid $60.1 million, $96.7 million and $76.7 million for interest during the years ended December 31, 2015, 2014 and 2013, respectively, net of capitalized interest. During the year ended December 31, 2015 the Company paid approximately $24 million for Reorganizations items.

During the year ended December 31, 2015, Sabine's noncash investing and financing activities consisted primarily of the following transactions:

- Offset rights taken by counterparties upon termination of derivative financial instruments were approximately $70.8 million, and were used to reduce obligations due under the New Revolving Credit Facility.
- Recognition of an asset retirement obligation for the plugging and abandonment costs related to Sabine O&G's oil and natural gas properties valued at $0.5 million.
- Accrued and payable capital expenditures as of December 31, 2015 were $8.7 million.

During the year ended December 31, 2014, Sabine's noncash investing and financing activities consisted primarily of the following transactions:

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The Combination with Forest Oil. Refer to Note 7 for preliminary allocation of consideration transferred to net assets acquired.

- Recognition of an asset retirement obligation for the plugging and abandonment costs related to Sabine's oil and natural gas properties valued at $0.7 million.
- Accrued and payable capital expenditures as of December 31, 2014 were $140.6 million.
- Accrued debt issuance costs as of December 31, 2014 were $0.5 million.

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During the year ended December 31, 2013, Sabine's noncash investing and financing activities consisted primarily of the following transactions:

- Recognition of an asset retirement obligation for the plugging and abandonment costs related to Sabine's oil and natural gas properties valued at $1.0 million.
- Accrued and payable capital expenditures as of December 31, 2013 were $90.3 million.

12.Derivative Financial Instruments

The Company's Bankruptcy Petition in July 2015 represented an event of default under Sabine's existing derivative agreements resulting in a termination right by counterparties on all derivative positions at July 15, 2015. Additionally, certain of the Company's derivative positions were terminated prior to July 15, 2015 as a result of defaults under Sabine's derivative agreements that occurred prior to the filing of the Bankruptcy Petition. The terminations resulted in settlements of approximately $24.3 million for which such proceeds were used to reduce our New Revolving Credit Facility. Other terminations resulted in approximately $70.8 million of direct offsets against the New Revolving Credit Facility. As a result, the Company no longer has any derivatives beyond July 2015.

In February 2015 the Company executed derivative contracts as market conditions allowed in order to economically hedge anticipated future cash flows from oil and natural gas producing activities. These included both oil and natural gas fixed-price swap agreements covering certain portions of anticipated 2016 and 2017 production volumes. Additionally, prior to the year ended December 31, 2015, the Company executed option contracts including purchased and written oil call agreements, as well as purchased oil put agreements, covering certain portions of anticipated 2016 oil production. No material premiums were recognized as a result of these option agreements. Sabine sold a swaption agreement allowing the counterparty the option to execute a fixed price swap agreement at a contracted price on contracted volumes before an expiration date. None of the fixed-price swap or option contracts were designated for hedge accounting, with all mark-to-market changes in fair value recognized currently in earnings.

Throughout the year ended December 31, 2014, the Company executed derivative contracts as market conditions allowed in order to economically hedge anticipated future cash flows from oil and natural gas producing activities. These include both oil and natural gas fixed-price swap agreements covering certain portions of anticipated 2015 production volumes. The Company executed option contracts including purchased and written oil and natural gas call agreements, as well as purchased and written oil and natural gas put agreements, covering certain portions of anticipated 2015 oil and natural gas production. Additionally, Sabine sold a swaption agreement allowing the counterparty the option to execute a fixed price swap agreement at a contracted price on contracted volumes before an expiration date. Sabine's sold swaption contract expired at December 31, 2015. No material premiums were recognized as a result of these option agreements. None of the fixed-price swap or option contracts were designated for hedge accounting, with all mark to market changes in fair value recognized currently in earnings.

The fair value for each derivative takes credit risk into consideration, whether it be Sabine's counterparties' or Sabine's own. Derivatives are classified as current or non-current derivative assets and liabilities, based on the expected timing of settlements.

The table below presents the Company's "Gain on derivative instruments" located in Other income (expenses) in the Consolidated Statements of Operations:

	For the Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Gain on derivative instruments	$ 33,897	$ 121,669	$ 814

Sabine received $92.0 million, paid $10.8 million and received $46.2 million on settlements of derivatives in 2015, 2014 and 2013, respectively.

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Sabine's derivative contracts are executed with counterparties under certain master netting agreements that allow the Company to offset assets due from, and liabilities due to, the counterparties. The table below presents the carrying value of Sabine's derivative assets and liabilities both before and after the impact of such netting agreements on the Consolidated Balance Sheets as of December 31, 2014. As a result of terminations, the Company no longer has any derivatives contracts in place at December 31, 2015:

	Derivative Assets as of December 31, 2014	
		Fair Value (in thousands)
Current assets	Derivative Instruments	$ 191,765
Total current asset fair value		191,765
Less: Counterparty set-off (1)		(31,548)
Total derivative asset net fair value		$ 160,217

	Derivative Liabilities as of December 31, 2014	
		Fair Value (in thousands)
Current liabilities	Derivative Instruments	$ (4,645)
Current assets	Derivative Instruments	(31,548)
Total current liability fair value		(36,193)
Long-term liabilities	Derivative Instruments	(2,269)
Total long-term liability fair value		(2,269)
Less: Counterparty set-off (1)		31,548
Total derivative liability net fair value		$ (6,914)

(1) Impact of counterparty right of set-off for derivative instruments subject to certain master netting agreements.

13.Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, marketable securities and listed equities.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

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Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category generally include non-exchange-traded derivatives such as commodity swaps, basis swaps, options, and collars.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

The following table sets forth, by level, within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2014. The Company's Bankruptcy Petition in July 2015 represented an event of default under Sabine's derivative agreements resulting in a termination right by counterparties on all derivative positions at July 15, 2015. As a result, all of Sabine's derivative agreements have been terminated and there are no outstanding derivative contracts as of December 31, 2015. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Recurring Fair Value Measurements (in millions)			
	Level 1	Level 2	Level 3	Total
As of December 31, 2014				
Derivative Assets	$ —	$ 191.8	$ —	$ 191.8
Derivative Liabilities	—	(38.5)	—	(38.5)
Total	$ —	$ 153.3	$ —	$ 153.3

The observable data includes the forward curve for commodity prices and interest rates based on quoted markets prices and prospective volatility factors related to changes in commodity prices, as well as the impact of the Company's non performance risk as well as the non-performance risk of its counterparties which is derived using credit default swap values.

The Company measures fair value of its debt based on recent trade activity for fixed rate obligations, Term Loan Facility, 2017 Notes, 2019 Notes and 2020 Notes, on a Level 2 methodology using quoted market prices which include consideration of the Company's credit risk. The following table outlines the fair value of the 2017 Notes, 2019 Notes and 2020 Notes as of December 31, 2015 and 2014:

	December 31, 2015	December 31, 2014
	(in thousands)	
New Revolving Credit Facility		
Carrying Value	$ 902,148	$ 545,000
Fair Value	(1)	$ 512,414
Term Loan Facility		
Carrying Value	$ 700,000	$ 696,916
Fair Value	(1)	$ 653,798
2017 Senior Notes		
Carrying Value (2)	$ 350,000	$ 348,669
Fair Value	$ 17,281	$ 190,400
2019 Senior Notes		
Carrying Value (2)	$ 577,914	$ 293,064
Fair Value	$ 27,090	$ 184,932
2020 Senior Notes		
Carrying Value (2)	$ 222,087	$ 105,234
Fair Value	$ 10,827	$ 73,311

(1) The New Revolving Credit Facility and Term Loan Facility were stated at the carrying value as of December 31, 2015, as a basis for fair value is indeterminable.

(2) At December 31, 2014 carrying value was equal to the face value, net of discount and were presented as a current liability in the Consolidated Balance Sheets. At December 31, 2015 the carrying value equals the face value and are presented as a long term liability in "Liabilities Subject to Compromise" in the Consolidated Balance Sheets.

Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition (Note 7). The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified as Level 3. Additionally, the Company uses fair value to determine the inception value of the Company's asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified as Level 3.

14.Commitments and Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. All known liabilities are accrued when probable and reasonably estimable based on the Company's best estimate of the potential loss. The Company has recognized $26.7 million of accrued liabilities in relation to legal proceedings which is classified within “Other long-term liabilities” and $2 million is classified within “Liabilities Subject to Compromise” in the Consolidated Balance Sheet as of December 31, 2015. As of December 31, 2014 the Company recognized $27.4 million of accrued liabilities in relation to legal proceedings which is classified within “Other long-term liabilities” in the Consolidated Balance Sheet. Additionally, as of December 31, 2015, the Company had AROs of approximately $40.9 million, of which $9.4 million was reported in “Liabilities Subject to Compromise” in the Consolidated Balance Sheet. As of December 31, 2014 Company had AROs of approximately $48.8 million, of which $9.4 million was reported in “Other short-term liabilities” in the Consolidated Balance Sheet attributable to the plugging of abandoned wells.

Forest Oil Corporation v. El Rucio Land and Cattle Company, Inc., et al.

On February 29, 2012, two members of a three-member arbitration panel reached a decision adverse to the Company in the proceeding styled Forest Oil Corp. et al. v. El Rucio Land & Cattle Co. et al. The third member of the arbitration panel dissented. The proceeding was initiated in January 2005 and involves claims asserted by the landowner-claimant based on the diminution in value of its land and related damages allegedly resulting from operational and reclamation practices employed by Forest Oil in the 1970s, 1980s, and early 1990s. The arbitration decision awarded the claimant $23 million in damages and attorneys' fees and additional injunctive relief regarding future surface-use issues. On October 9, 2012, after vacating a portion of the decision imposing a future bonding requirement on the Company, the trial court for the 55th Judicial District of Harris County, Texas, reduced the arbitration decision to a judgment. The judgment was affirmed by the Court of Appeals for the First District of Texas on July 24, 2014, and a motion for rehearing was denied on August 8, 2014. The Company filed a petition for review with the Texas Supreme Court on January 5, 2015. On May 1, 2015, the Texas Supreme Court requested full briefing on the merits. On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. On September 15, 2015, the bankruptcy court granted an unopposed motion to lift the automatic stay thereby allowing the appeal currently pending in the Texas Supreme Court to move forward. All briefing in the matter is now completed.

Stourbridge Investments, LLC v. Forest Oil Corporation, et al., Raul v. Carroll, et al., Rothenberg v. Forest Oil Corporation, et al., Gawlikowski v. Forest Oil Corporation, et al., Edwards v. Carroll, et al., Jabri v. Forest Oil Corporation, et al., Olinatz v. Forest Oil Corporation, et al.

Following the May 6, 2014 announcement of the proposed Combination, six putative class action lawsuits were filed by Forest Oil shareholder in the Supreme Court of the State of New York, County of New York, alleging breaches of fiduciary duty by the directors of Forest Oil and aiding and abetting of those breaches of fiduciary duty by Sabine entities in connection with the proposed Combination. By order dated July 8, 2014, the six New York cases were consolidated for all purposes under the caption In re Forest Oil Corporation Shareholder Litigation, Index No. 651418/2014. On July 17, 2014, plaintiffs in the consolidated New York action filed a Consolidated Class Action Complaint (the "Consolidated Complaint"). The Consolidated Complaint seeks to certify a plaintiff class consisting of all holders of Forest Oil common stock other than the defendants and their affiliates. The defendants named in these actions include the directors of Forest Oil (Patrick R. McDonald, James H. Lee, Dod A. Fraser, James D. Lightner, Loren K. Carroll, Richard J. Carty, and Raymond I. Wilcox), as well as Sabine and certain of its affiliates (specifically, Sabine Oil & Gas LLC, Sabine Investor Holdings LLC, Sabine Oil & Gas Holdings LLC, and Sabine Oil & Gas Holdings II LLC). The Consolidated Complaint also purports to identify FR XI Onshore AIV, L.L.C. as a defendant, but no causes of action are alleged against that entity.

The Consolidated Complaint alleges that the proposed Combination arises out of a series of unlawful actions by the board of directors of Forest Oil seeking to ensure that Sabine and affiliates of First Reserve Corporation ("First Reserve") acquire the assets of, and take control over, Forest Oil through an alleged "three-step merger transaction" that allegedly does not represent a value-maximizing transaction for the shareholders of Forest Oil. The Consolidated Complaint also complains that the proposed Combination has been improperly restructured to require only a majority vote of current Forest Oil shareholders to approve the Combination with Sabine, rather than a two-thirds majority as would have been required under the original transaction structure. The Consolidated Complaint additionally alleges that members of Forest Oil's board, as well as Forest Oil's financial adviser for the proposed Combination, are subject to conflicts of interest that compromise their loyalty to Forest Oil's shareholders, that the defendants have improperly sought to "lock up" the proposed Combination with certain inappropriate "deal protection devices" that impede Forest Oil from pursuing superior potential transactions with other bidders.

The Consolidated Complaint asserts causes of action against the directors of Forest Oil for breaches of fiduciary duty and violations of the New York Business Corporation Law, as well as a cause of action against the Sabine defendants for aiding and abetting the directors' breaches of duty and violations of law, and it seeks preliminary and permanent injunctive relief to enjoin consummation of the proposed Combination or, in the alternative, rescission and/or rescissory and other damages in the event that the proposed Combination is consummated before the lawsuit is resolved.

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In addition to these New York proceedings, one putative class action lawsuit has been filed by Forest Oil shareholders in the United States District Court for the District of Colorado. That action, captioned Olinatz v. Forest Oil Corp., No. 1:14-cv-01409-MSK-CBS, was commenced on May 19, 2014, and plaintiffs filed an Amended Complaint (the "Olinatz Complaint") on June 13, 2014. The Olinatz Complaint also alleges breaches of fiduciary duty by the directors of Forest Oil and aiding and abetting of those breaches of fiduciary duty by the Sabine defendants in connection with the proposed Combination, as well as related claims alleging violations of Section 14 (a) and 20 (a) of the Securities Exchange Act of 1934, and Securities and Exchange Commission Rule 14a-9 promulgated thereunder, in connection with alleged misstatements in a Form S-4 Registration Statement filed by Forest Oil on May 29, 2014, which recommends that Forest Oil shareholders approve the proposed Combination. The Olinatz Complaint names as defendants Forest Oil and certain of its affiliates (specifically, Forest Oil Corporation, New Forest Oil Inc., and Forest Oil Merger Sub Inc.), the directors of Forest Oil (Patrick R. McDonald, James H. Lee, Dod A. Fraser, James D. Lightner, Loren K. Carroll, Richard J. Carty, and Raymond I. Wilcox), and Sabine and certain of its affiliates (specifically, Sabine Oil & Gas LLC, Sabine Investor Holdings LLC, Sabine Oil & Gas Holdings LLC, and Sabine Oil & Gas Holdings II LLC), and seeks preliminary and permanent injunctive relief to enjoin consummation of the proposed Combination or, in the alternative, rescission in the event the proposed Combination is consummated before the lawsuit is resolved, as well as imposition of a constructive trust on any alleged benefits improperly received by defendants.

On October 14, 2014, on motion by the Colorado plaintiffs, the Court in the Colorado action entered an order directing the Clerk of the Court to administratively close the action, subject to reopening on good cause shown.

On November 11, 2014, the defendants reached an agreement in principle with plaintiffs in the New York action regarding a settlement of that action, and that agreement is reflected in a memorandum of understanding executed by the parties on that date. The settlement, if consummated, would also resolve the Colorado action. In connection with the settlement contemplated by the memorandum of understanding, Forest Oil agreed to make certain additional disclosures related to the proposed transaction with Sabine, which are contained in Forest Oil's November 12, 2014 Form 8-K, and Sabine agreed that, within 120 days after the closing of the proposed combination transaction, Sabine Investor Holdings LLC will designate for a period of no less than three (3) years at least one additional independent director, as defined in Section 303A.02 of the New York Stock Exchange Listed Company Manual, as a Sabine Nominee (as defined in Section 1.4 of the Amended and Restated Agreement and Plan of Merger). The total number of Sabine Nominees will remain unchanged, but at least one of the remaining two Sabine Nominees that had not yet been determined was required to be independent. In connection with the closing of the Combination, Thomas Chewning, an independent director as defined in Section 303A.02 of the New York Exchange Listed Company Manual, was appointed as a Sabine Nominee. The memorandum of understanding contemplates that the parties will enter into a stipulation of settlement.

On March 13, 2015, plaintiffs informed Sabine that they believed Sabine had materially violated the terms of the memorandum of understanding by (i) failing to replace or create a mechanism to replace an independent director who resigned from the board of directors in January of 2015, and (ii) making changes to the terms of the merger agreement that were not necessary or required to facilitate the consummation of the proposed transaction without first disclosing and permitting shareholders to vote on the changes. Sabine disagrees with plaintiffs' position and believes it has fully complied with the memorandum of understanding. In an attempt to facilitate a resolution, however, Sabine offered to: (i) appoint an independent director if an additional director was added to the Board of Directors (bringing the total number of directors to eight) in the next twelve months, and (ii) remove or waive the "Reincorporation Penalty" provision. Plaintiffs accepted the offer on April 22, 2015, contingent upon the Parties' reaching agreement on a stipulation of settlement, which they are presently negotiating.

The stipulation of settlement will be subject to customary conditions, including court approval. In the event the parties enter into a stipulation of settlement, a hearing will be scheduled at which the New York Court will consider the fairness, reasonableness, and adequacy of the settlement. If the settlement is finally approved by the court, it will resolve and release all claims or actions that were or could have been brought challenging any aspect of the proposed combination transaction, the Amended and Restated Agreement and Plan of Merger, the merger agreement originally entered into by Sabine Investor Holdings LLC, Forest Oil, New Forest Oil Inc. and certain of their affiliated entities on May 5, 2014, any disclosure made in connection therewith, including the Definitive Proxy Statement, and all other matters that were the subject of the complaint in the New York action, pursuant to terms that will be disclosed to shareholders prior to final approval of the settlement. In addition, in connection with the settlement, the parties contemplate that the parties will negotiate in good faith regarding the amount of attorney's fees and expenses that shall be paid to plaintiffs' counsel in connection with the Actions. There can be no assurances that the parties will ultimately enter into a stipulation of settlement or that the New York Court will approve the settlement even if the parties were to enter into such stipulation. In such event, the proposed settlement as contemplated by the memorandum of understanding may be terminated. The parties are presently negotiating the stipulation of settlement. At this time, the Company is unable to estimate the potential outcome of this litigation or the ultimate exposure.

On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As a result of the pending bankruptcy, this matter is currently stayed.

HPIP-Gonzales Holdings, LLC v. Forest Oil Corporation

On November 11, 2014, HPIP-Gonzales Holdings, LLC ("HPIP") initiated arbitration against the Company alleging that the Company breached various provisions, along with its duty of good faith and fair dealing, of the Gathering, Treating and Processing Agreement with HPIP entered into in May 2013 and the Acid Gas Handling Agreement with HPIP entered into in May 2014 (collectively, the "HPIP Agreements"). HPIP also sought to exercise a contractual provision requiring Sabine to purchase the facilities governed by the HPIP agreements in the event the related drilling program terminates. On December 19, 2014, the Company filed its Answering Statement and Notice of Counterclaim, denying HPIP's claims and asserting generally that HPIP breached various provisions of the agreements, resulting in damages to the Company. The Company further alleged that its drilling program had not terminated. On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As a result of the pending bankruptcy, the arbitration is currently stayed.

On March 8, 2016, the bankruptcy court announced that it would approve rejection of the HPIP Agreements, effective retroactively to September 30, 2015 (but an order has not yet been entered). The Company will continue to vigorously further defend against any damages asserted by HPIP.

Wilmington Savings Fund Society, FSB v. Forest Oil Corporation

On February 26, 2015, the Company was served with a complaint concerning the indenture governing its 2019 Notes. The complaint is pending in the Supreme Court of the State of New York and generally alleges that certain events of default occurred with respect to the 2019 Notes due to the business combination between Forest Oil Corporation and Sabine Oil & Gas LLC. The Company also received a notice of default and acceleration from the trustee with respect to the 2019 Notes containing similar allegations. If the Company is not successful in their defense of this complaint, the Company may be required to redeem the holders of the 2019 Notes at 101% of the outstanding principal, plus accrued and outstanding interest of the notes. The Company filed its Answer to the complaint on April 17, 2015. The Company believes the allegations against it are without merit and intend to vigorously defend against such claims and pursue any and all defenses available. However, the Company is unable to predict the outcome of such matter, and the proceedings may have a negative impact on the Company's liquidity, financial condition and results of operations.

The Company is separately evaluating potential claims that it may assert against the trustee for the 2019 Notes for any and all losses the Company may suffer as a result of the complaint or notice. The Company can provide no guarantee that any such claims, if brought by the Company, will be successful or, if successful, that the responsible parties will have the financial resources to address any such claims. While the Company intends to vigorously defend the claims against it and believe they are without merit, an adverse ruling could cause the Company's indebtedness to become immediately due and payable.

Additional claims, lawsuits, or proceedings may be filed or commenced arising out of the indentures to which we are a party and with respect to the business combination.

On July 15, 2015, the Company filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As a result of the pending bankruptcy, this matter is currently stayed.

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Sabine Oil & Gas Corporation v. Wilmington Trust, N.A.

On July 15, 2015, the Company filed an adversary proceeding asserting, on its behalf, a constructive fraudulent transfer claim against the Term Loan Facility administrative agent Wilmington Trust, N.A. Specifically, the complaint states that immediately before the Combination between Sabine Oil & Gas LLC and Forest Oil Corporation, both Forest Oil Corporation and Sabine Oil & Gas LLC were insolvent from a balance-sheet standpoint. The complaint likewise alleges that immediately after the Combination, the combined company was insolvent. The complaint also alleges that Forest Oil Corporation and its creditors did not receive reasonably equivalent value in the Combination and financing transactions that occurred simultaneously on December 16, 2014. Specifically the complaint alleges that Forest Oil Corporation's creditors did not receive reasonably equivalent value in exchange for pledging hundreds of millions of previously unencumbered dollars of oil and gas assets to secure the Term Loan Facility debt that was under-secured, and that Sabine Oil & Gas LLC had previously incurred. Accordingly, pursuant to Bankruptcy Code Section 551, the Company is seeking to avoid and preserve, for the benefit of the Company's unsecured creditors, the liens imposed on legacy Forest Oil Corporation assets that were pledged to secure the preexisting Sabine Oil & Gas LLC's Term Loan Facility. In August 2015, the defendant filed a motion to dismiss, which is not fully briefed. The court first heard oral argument on October 15, 2015, but did not rule.

On December 30, 2015, the official committee for unsecured creditors (the "Creditors Committee") and counsel for the Forest Notes Trustees filed motions to intervene in the adversary proceeding. On January 5, 2016, the Creditors Committee also filed an objection to Wilmington Trust, N.A.'s motion to dismiss the complaint. The court held a second hearing on the motion to dismiss on January 12, 2016, but has yet to rule.

Drilling & Completion

On August 10, 2015 the Bankruptcy Court issued orders allowing the Company to reject its rig and servicing contracts with Nabors effective July 15, 2015 and the total estimated allowable claim has been included in "Liabilities Subject to Compromise" in the Consolidated Balance Sheet" and "Reorganization Items, net" in the Consolidated Statements of Operations" as appropriate. The rejections impacted the Company's rigs and servicing and eliminated approximately $29 million due over the life of the secured contracts as of the date the contracts were rejected.

On March 8, 2016, the bankruptcy court announced that it would approve rejection of the HPIP Agreements, effective retroactively to September 30, 2015 (but an order has not yet been entered). This rejection eliminates the obligation to drill at least one well per year on the relevant acreage in order to avoid triggering the agreement's put provision, which would require the Company to purchase the gathering and processing facilities at a contractually mandated price if the drilling program terminated prior to May 2, 2017.

As is customary in the oil and natural gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not pay such commitments, the acreage positions or wells may be lost.

Other Commitments

The Company's filing of the Bankruptcy Petitions described in Note 2 herein constituted an event of default that accelerated the Company's obligations under the New Revolving Credit Facility, the Term Loan Facility, the 2017 Notes and the Legacy Forest Notes. As a result, the Company has classified all debt as "Liabilities Subject to Compromise" in the Consolidated Balance Sheet as of December 31, 2015. For additional description of the defaults present under the Company's debt obligations, please see Note 8 herein.

The Bankruptcy Court also issued orders allowing the Company to reject certain office leases effective September 1, 2015 and the total estimated allowable claim of approximately $3.6 million has been included in “Liabilities Subject to Compromise” in the Consolidated Balance Sheet as of December 31, 2015 and “Reorganization Items, net” in the Consolidated Statements of Operations for year ended December 31, 2015, as appropriate.

During 2014, the Company executed ten year gas and condensate gathering agreements for the transportation and processing of natural gas and condensate, covering certain properties in South Texas with contractually obligated annual minimum volume commitments to deliver a cumulative 88.5 Bcfe of gas and 5,150 MBbl of condensate by September 22, 2024 (“the South Texas Agreements”). Under the terms of the South Texas Agreements, the Company is required to make annual deficiency payments for any shortfalls in delivering the minimum annual volumes under these commitments beginning in the third quarter of 2015, which shall be partially offset by then-existing credit balances for production in excess of minimum commitments, if any. As of December 31, 2015, the Company had not delivered the minimum volumes required for the prior contract year, resulting in a deficiency of approximately $3.0 million which was recognized as “Other operating expenses” in the Consolidated Statement of Operations and as “Liabilities subject to compromise” in the Consolidated Balance Sheets. As of December 31, 2015, the Company has not made the deficiency payment. Based on the current development plan for these oil and gas assets, the Company does not anticipate that future production from the applicable assets and dedicated area will satisfy the future volume commitments, resulting in substantial deficiency payments over the life of the agreements. In order to avoid these substantial future deficiency payments, the Company filed a motion in the bankruptcy court to reject the South Texas Agreements. On March 8, 2016, the bankruptcy court announced that it would approve rejection of the South Texas Agreements, but an order has yet to be entered. The Company believes that rejection will eliminate any future obligation under the agreements to deliver minimum volumes of gas or condensate, or to make deficiency payments in the event minimum volumes are not delivered. The future contractual obligations of the South Texas Agreements total approximately $30.2 million as of December 31, 2015.

The Company has executed additional gas gathering agreements for the transportation and processing of natural gas, covering certain properties in our core operating areas and contractually obligated minimum volume commitments to deliver a cumulative 6.8 Bcfe of gas by August 2018. Under the terms of these agreements, the Company is required to make deficiency payments at the end of the contractual term for any shortfalls in delivering the minimum volumes under these commitments. Based on the current development plan for these oil and gas assets, the Company does not anticipate that future production from the applicable assets and dedicated area will satisfy the future volume commitments, resulting in deficiency payments over the life of the agreements. As of December 31, 2015, the Company has recognized an estimated deficiency of approximately $1.3 million which was recognized as Other operating expenses in the Consolidated Statements of Operations and as Liabilities subject to compromise in the Consolidated Balance Sheets. The future contractual obligations of the agreements total approximately $6.3 as of December 31, 2015.

The Company leases approximately 73,000 square feet of office space in downtown Houston, Texas, under a lease, which was amended effective January 1, 2014 to terminate on April 30, 2016. The average rent for this space over the life of the lease is approximately $1.6 million per year. As of December 31, 2015, total future commitments are $0.8 million.

Rent expense was approximately $6.3 million, $2.6 million and $1.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

The Company leases various office and production equipment. As of December 31, 2015, total future commitments are $0.7 million. The majority of Sabine’s operating leases continue with a month to month lease term after initial contractual obligations have expired.

A summary of Sabine’s contractual obligations as of December 31, 2015 is provided in the following table:

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Payments due by period

	For the Year Ending December 31,						
	2016	2017	2018	2019	2020	Thereafter	Total
Senior secured revolving credit facility (1)	$ 902.1	$ —	$ —	$ —	$ —	$ —	$ 902.1
Term Loan Facility (2)	700.0	—	—	—	—	—	700.0
2017 Senior Notes (2)	350.0	—	—	—	—	—	350.0
2019 Senior Notes (2)	577.9	—	—	—	—	—	577.9
2020 Senior Notes (2)	222.1	—	—	—	—	—	222.1
Office and equipment leases	1.4	0.1	—	—	—	—	1.5
Operating commitments (3)	8.8	9.8	4.7	3.2	2.6	7.4	36.5
Other (4)	14.0	4.3	4.1	4.0	3.8	59.8	90.0
Total	$ 2,776.3	$ 14.2	$ 8.8	$ 7.2	$ 6.4	$ 67.2	$ 2,880.1

(1) Includes outstanding principal amounts that were accelerated during 2015. As of December 31, 2015, the New Revolving Credit Facility is presented as "Liabilities Subject to Compromise," whereas the carrying value equals the face value. Interest expense continues to be recognized on the New Revolving Credit Facility subsequent to the petition date. This table does not include future commitment fees, interest expense or other fees on these facilities because they are floating rate instruments and Sabine cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged. As of December 31, 2015, the New Revolving Credit Facility had a weighted average interest rate of 4.02%. For more information on the classification of debt, please see Note 2 herein.

(2) As of December 31, 2015, the 2017 Notes, the 2019 Notes, the 2020 Notes and the Term Loan Facility are presented as "Liabilities Subject to Compromise," whereas the carrying value equals the face value. Accrued interest through the petition date was approximately $74.2 million. No interest expense has been recognized subsequent to the petition date. For more information on the classification of debt, please see Note 2 herein.

(3) The Company is party to gas and condensate gathering agreements for the transportation and processing of natural gas and condensate for certain properties which provided for contractually obligated annual minimum volume commitments of gas and condensate. Under the terms of the agreements, the Company is required to make annual deficiency payments for any shortfalls in delivering the minimum volumes under these commitments.

(4) Other is comprised primarily of pension and other postretirement benefit obligations, asset retirement obligations and future settlements of deferred service charges, for which neither the ultimate settlement amounts nor the timing of settlement can be precisely determined in advance. See "Critical Accounting Policies, Estimates, Judgments, and Assumptions" in this Annual Report on Form 10-K for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

15.Employee Benefit Plans

Pension Plans and Postretirement Benefits

As a result of the Combination between Sabine and Forest, Sabine assumed qualified defined benefit pension plans (the "Forest Pension Plan" and the "Wiser Pension Plan"). Sabine also assumed non-qualified unfunded supplementary retirement plans (the "Forest SERP" and the "THX SERP," and together, the "SERP") that provide certain retired executives with defined retirement benefits in excess of qualified plan limits imposed by federal tax law. The Forest Pension Plan and the Forest SERP were curtailed and all benefit accruals under both plans were suspended effective May 31, 1991. The Wiser Pension Plan was curtailed and all benefit accruals were suspended effective December 11, 1998. The THX SERP was curtailed and all benefit accruals were suspended effective January 1, 2008. The Forest Pension Plan, the Wiser Pension Plan, the Forest SERP, and the THX SERP are hereinafter collectively referred to as the

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"Pension Plans." Effective December 23, 2015, Sabine's board of directors approved a resolution to terminate the SERP plan.

In addition to the Pension Plans described above, as a result of the Combination between Sabine and Forest, Sabine also assumed a plan that provides postretirement benefits to certain former Forest employees hired on or prior to January 1, 2009, their beneficiaries, and covered dependents. These medical and dental benefits are hereinafter referred to as the "Postretirement Benefits Plan."

Expected Benefit Payments

As of December 31, 2015, it is anticipated Sabine will be required to provide benefit payments from the Forest Pension Plan trust and the Wiser Pension Plan trust and the Postretirement Benefits Plan in the following amounts:

	2016	2017	2018	2019	2020	2021 - 2025
	(in thousands)					
Forest Pension Plan (1)	$ 2,220	$ 2,206	$ 2,178	$ 2,118	$ 2,079	$ 9,317
Wiser Pension Plan (1)	874	865	846	830	812	3,843
Postretirement Benefits Plan	551	563	544	529	510	2,356

(1) Benefit payments expected to be made to participants in the Forest Pension Plan and Wiser Pension Plan are expected to be paid out of funds held in trusts established for each plan.

Sabine anticipates that it will make contributions in 2016 totaling $0.5 million to the Pension Plans and $0.5 million to the Postretirement Benefits Plan, net of retiree contributions, as applicable.

Benefit Obligations

The following table sets forth the estimated benefit obligations associated with the Pension Plans and Postretirement Benefits Plan.

	Year Ended December 31, 2015		Year Ended December 31, 2014	
	Pension Plans	Postretirement Benefits Plan	Pension Plans	Postretirement Benefits Plan
	(in thousands)		(in thousands)	
Benefit obligation at the beginning of the year	$ 44,400	$ 18,052	$ —	$ —
Service cost	—	74	—	—
Interest cost	1,479	273	—	—
Amendments	—	90	—	—
Actuarial (gain)/loss	(3,061)	(413)	—	—
Benefits paid	(3,172)	(584)	—	—
Business combination	(440)	(10,383)	44,400	18,052

Benefit obligation at the end of the year	$ 39,206	$ 7,109	$ 44,400	$ 18,052

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Fair Value of Plan Assets

The assets of the Forest Pension Plan and the Wiser Pension Plan measured at fair value on a recurring basis are set forth by level within the fair value hierarchy in the table below. There are no assets set aside under the Postretirement Benefits Plan.

	December 31, 2015			
	Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Using Significant Other Observable Inputs (Level 2)	Using Significant Unobservable Inputs (Level 3)	Total (1)
	(in thousands)			
Cash and cash equivalents	$ 183	$ 64	$ —	$ 247
Investment funds—equities:				
Research equity portfolio(1)	—	9,778	—	9,778
International stock funds(2)	11,086	—	—	11,086
Investment funds—fixed income:				
Short-term fund(3)	1,985	—	—	1,985
Bond fund(4)	6,078	—	—	6,078
Oil and gas royalty interests(5)	—	—	172	172
	$ 19,332	$ 9,842	$ 172	$ 29,346

(1) This investment fund's assets are primarily large capitalization U.S. equities. The investment approach of this fund, which held approximately 224 different securities at December 31, 2015, focuses on diversifying the investment portfolio by delegating the equity selection process to research analysts with expertise in their respective industries. Industry weights are kept similar to those of the S&P 500 Index. As of December 31, 2015, the approximate sector weighting of this fund was comprised of the following: financials (18%), information technology (18%), health care (16%), consumer discretionary (13%), consumer staples (12%), industrials (11%), and other (12%). The fair value of this investment fund was determined based on the net asset value per unit provided by the fund. Sabine performs procedures to validate the net asset value per unit provided by the fund. Such procedures include verifying the pricing of a sample of the underlying securities, with such pricing being directly observable in the marketplace.

(2) These three investment funds seek long-term growth of principal and income by investing primarily in diversified portfolios of equity securities issued by foreign, medium-to-large companies in international markets including emerging markets. The first fund, which comprises $6.4 million of the international stock funds, seeks to invest in solid, well-established global leaders with emphasis on strong corporate governance, positive future growth opportunities, and growing return on capital. As of December 31, 2015, the approximate sector weighting of this fund, which seeks diversification across regions, countries, and market sectors, was comprised of the following: financials (23%), information technology (23%), health care (14%), consumer discretionary (10%), and other (30%). The second fund, which comprises $3.4 million of the international stock funds, seeks to obtain growth through long-term appreciation of its holdings, selecting investments based upon their current fundamentals. As of December 31, 2015, the approximate sector weighting of this fund, which invests in Asian (excluding Japanese)

growth equities with a focus on domestic demand growth rather than an export orientation, was comprised of the following: consumer staples (20%), financials (18%), information technology (16%), consumer discretionary (11%), healthcare (11%) and other (24%). The third fund, which comprises $1.3 million of the international stock funds, seeks to deliver equity-like returns with significantly less volatility by investing in emerging markets equity securities, with country allocations not exceeding 25%. As of December 31, 2015, the approximate sector weighting of this fund was comprised of the following: Short-term securities (26%), information technology (11%), financials (10%), industrials (10%), and other (43%). The fair value of these investment funds was determined based on the funds' net asset values per unit, which are directly observable in the marketplace.

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(3) This investment fund's assets are high-quality short-term fixed income securities. This fund generally limits its foreign currency exposure to 20% of its total assets and is actively managed as an enhanced cash strategy, seeking to derive excess returns versus money market fund indices by capturing term, transactional liquidity, credit, and volatility premiums. As of December 31, 2015, the approximate sector weighting of this fund was comprised of the following: cash and cash equivalents (31%), corporate (29%), government related (18%), derivative (13%) and other (9%). The fair value of this investment fund was determined based on the fund's net asset value per unit, which is directly observable in the marketplace.

(4) These two investment funds consist of diversified portfolios of bonds. The main investments of the first fund, which comprises $4.9 million of the bond fund, are intermediate maturity fixed income securities with a duration between three and six years, with a maximum of 10% of the portfolio being invested in securities below Baa grade, and up to 30% of the portfolio being invested in non-U.S. dollar denominated securities. As of December 31, 2015, the approximate sector weighting of this fund was comprised of the following: government-related (38%), cash and cash equivalents (27%), securitized (18%), derivative (10%) and other (7%). The second fund, which comprises $1.2 million of the bond fund, seeks to deliver equity-like returns with significantly less volatility by investing in emerging markets debt securities, with country allocations not exceeding 25%. As of December 31, 2015, the approximate sector weighting of this fund was comprised of the following: government related (74%), energy (10%) and other (16%). The fair value of these investment funds was determined based on the funds' net asset values per unit, which are directly observable in the marketplace.

(5) The oil and gas royalty interests are valued at their estimated discounted future cash flows, which approximate fair value.

The following table sets forth a rollforward of the fair value of the plan assets.

	Year Ended December 31, 2015		Year Ended December 31, 2014	
	Pension Plans	Postretirement Benefits Plan	Pension Plans	Postretirement Benefits Plan
	(in thousands)		(in thousands)	
Fair value of plan assets at beginning of the year	$ 31,395	$ —	$ —	$ —
Actual return on plan assets	(556)	—	—	—
Employer contributions	1,679	494	—	—
Participant contributions	—	90	—	—
Benefits paid	(3,172)	(584)	—	—
Business combination	—	—	31,395	—
Fair value of plan assets at the end of the year	$ 29,346	$ —	$ 31,395	$ —

The following table presents a reconciliation of the beginning and ending balances of the plan assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Year Ended December 31, 2015 Oil and Gas Royalty Interests (in thousands)		Year Ended December 31, 2014 Oil and Gas Royalty Interests (in thousands)	
Balance at beginning of period	$	199	$	—
Actual return on plan assets		(27)		—
Purchases, sales, and settlements (net)		—		199
Transfers in and/or out of Level 3		—		—
Balance at end of period	$	172	$	199

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Investments of the Plans

The Forest Pension Plan and the Wiser Pension Plan assets are invested with a view toward the long-term in order to fulfill the obligations promised to participants as well as to control future funding levels. Sabine plans to regularly review the levels of funding and investment strategy for the pension plans. Generally, the strategy includes allocating the assets between equity securities and fixed income securities, depending on economic conditions and funding needs, although the strategy does not define any specified minimum exposure for any point in time. The equity and fixed income asset allocation levels in place from time to time are intended to achieve an appropriate balance between capital appreciation, preservation of capital, and current income.

The overall investment goal for the pension plans' assets is to achieve an investment return that allows the assets to achieve the assumed actuarial interest rate and to exceed the rate of inflation. In order to manage risk, in terms of volatility, the portfolios are designed with the intent of avoiding a loss of 20% during any single year and expressing no more volatility than experienced by the S&P 500 Index. The pension plans' investment allocation target is up to 75% equity, with discretion to vary the mix temporarily, in response to market conditions.

The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan are set forth in the following table:

December 31, 2015		December 31, 2014	
Forest Pension Plan	Wiser Pension Plan	Forest Pension Plan	Wiser Pension Plan