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, 2014
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	OTCQB 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, 2014 was approximately $268 million, based upon the closing price of $2.28 per share as reported by the New York Stock Exchange on such date.

214,669,984 shares of our $0.10 par value common stock were outstanding on March 15, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's notice of annual meeting of shareholders and proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Form 10-K.

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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 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 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:

- "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.
- "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

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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 t which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the 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:

- 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;
- 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;

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- 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.

Our Properties

Overview

Our properties are primarily focused in three core geographic areas:

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

As of December 31, 2014, we held interests in approximately 278,500 gross (219,200 net) acres in East Texas, 88,100 gross (58,700 net) acres in South Texas and 51,400 gross (36,900 net) acres in North Texas. As of December 31, 2014, we were the operator on 89%, 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.

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The 2014 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 2014 capital expenditures were approximately $562 million, including approximately $512 million on drilling and completion activities and approximately $50 million on leasing and other activities. Drilling and completion expenditures included approximately $149 million for the development of proved undeveloped reserves and approximately $363 million for the development of unproved reserves. Our full year 2015 capital expenditures are forecasted to total approximately $230 million to $275 million.

Our Acquisition History

During 2012 through 2014, we successfully completed the Combination as well as additional acquisitions that, coupled with farm out agreements, 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. Our key acquisitions and development activities during such period were as follows:

- We established our initial position in the Eagle Ford Shale in South Texas in 2012 through a farm-out agreement, which obligated us to drill and complete two wells in the play to earn approximately 15,500 net acres. Subsequently, we have grown our position in the Eagle Ford Shale to approximately 34,800 net acres as of December 31, 2014, excluding the effects of the Combination, via four additional transactions and grass roots leasing.
- In December 2012, we acquired interests in over 60,000 net leasehold acres with then-current net production of approximately 6,500 Boe/d, which established our position in the Granite Wash and Cleveland Sand in North Texas. We have since divested the Cleveland Sand assets. Our remaining net acres in the Granite Wash were approximately 36,900 net acres as of December 31, 2014, which includes the acquisitions of additional interests through two 2014 transactions.
- In December 2014, we completed the Combination, under which we combined the respective businesses of Sabine O&G and Forest.

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 foreign 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 1,197 Bcfe as of December 31, 2014, of which 78% is natural gas and 51% is developed. As of December 31, 2014, our properties were producing from 1,282 wells in East Texas, and we operated 1,125, or 88%, of those wells. Average net daily production in East Texas from our properties for the three months ended December 31, 2014 was 170 MMcfe/d, on a pro forma basis after giving effect to the

Combination.

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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, 2014, approximately 182,200 gross (145,500 net) acres of this East Texas position was prospective for the liquids-rich Cotton Valley Sand formation, 89% of which was held by production. As of December 31, 2014, our properties produced from 101 horizontal and 1,099 vertical wells in the Cotton Valley Sand, and we operated 1,056, or 88%, of those wells.
- Haynesville Shale—As of December 31, 2014, approximately 86,100 gross (70,000 net) acres of our East Texas position was prospective for the Haynesville Shale, 81% of which was held by production. Approximately 9,900 gross (9,400 net) of this acreage is located in Red River Parish, Louisiana. As of December 31, 2014, we produced from 73 horizontal wells in the Haynesville Shale, and we operated 69, or 84%, of those wells.
- Other—As of December 31, 2014, approximately 60,100 gross (46,600 net) of our East Texas position represents acreage located primarily in Cherokee, Leon, Angelina, Freestone, Wood and Bowie Counties, 67% of which is held by production.

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, 2014, our properties represented interests in approximately 88,100 gross (58,700 net) acres in DeWitt, Lavaca and Gonzales Counties prospective for the Eagle Ford Shale, approximately 59% of which was held by production. This area had estimated proved reserves of 106 Bcfe as of December 31, 2014, of which 67% was oil or NGLs and 92% was developed. As of December 31, 2014, our properties were producing from 186 wells in South Texas, and we operated 184, or 99%, of those wells. Average net daily production associated with our properties in South Texas for the three months ended December 31, 2014 was 78 MMcfe/d, on a pro forma basis after giving effect to the Combination.

Primary operations are in the following areas:

- Sugarkane Area—As of December 31, 2014, the Sugarkane area included approximately 3,000 gross (2,700 net) acres, 93% of which was held by production. As of December 31, 2014, our properties were producing from 20 horizontal wells, 19 of which we operated. The shape of this acreage block makes it well-suited for full field pad development, and we are the operator for all of our identified drilling locations.
- Shiner Area—As of December 31, 2014, the Shiner area included-approximately 38,500 gross (32,000 net) acres, 32% of which was held by production. As of December 31, 2014, our properties were producing from 48 horizontal wells, 47 of which we operated.
- Eagleville Area—As of December 31, 2014, the Eagleville area included approximately 46,600 gross (24,000 net) acres, 92% of which was held by production. As of December 31, 2014, our properties were producing from 118 horizontal wells, all 118 of which we operated.

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, 2014, we held rights to develop approximately 51,400 gross (36,900 net) acres primarily in Roberts County in Texas, approximately 13% of which was held by production. The North Texas acreage as of December 31, 2014 includes approximately 32,200 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 32,200 net acre position.

This area has estimated proved reserves of 43 Bcfe as of December 31, 2014, of which 71% was oil or NGLs and 62% was developed. As of December 31, 2014, our properties were producing from 49 wells in North Texas, 92% of which we operated. Average net daily production in North Texas for the three months ended December 31, 2014 was 27 MMcfe/d on a pro forma basis after giving effect to the Combination.

Other

As of December 31, 2014, our position outside of our three core geographic areas included approximately 77,800 gross (35,300 net) acres primarily in North Dakota, South Dakota, Mississippi and Wyoming.

Estimated Proved Reserves

The information with respect to our estimated proved reserves as of December 31, 2014 and December 31, 2013 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 January 20, 2015 and January 24, 2014. 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, 2014 and December 31, 2013 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 the estimated present value of our 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,	
	2014 (1)	2013 (2) (3)
	Proved reserves (Bcfe)	Proved reserves (Bcfe)
Operating area		
East Texas (4)	1,198	596
South Texas	106	182
North Texas	43	61
Other (5)	10	—
Total	1,357	839

(1) 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 12 months of $94.99 per Bbl for oil and (b) Henry Hub spot market prices

for the prior 12 months of $4.35 per MMbtu for natural gas.

(2) Data for December 31, 2013 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior 12 months of $96.78 per Bbl for oil and (b) Henry Hub spot market prices for the prior 12 months of $3.67 per MMbtu for natural gas.

(3) Estimates of proved reserves relate only to those associated with the Sabine O&G Properties at December 31, 2013.

(4) Includes Northern Louisiana.

(5) Includes Wyoming, North Dakota and the Permian Basin.

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

	At December 31,	
	2014 (1)	2013 (2) (3)
Estimated proved reserves:		
Oil (MMBbl)	20.1	16.9
NGLs (MMBbl)	41.1	25
Natural gas (Bcf)	989.8	588.1
Total estimated proved reserves (Bcfe)	1,357.2	839.3
Proved developed producing reserves:		
Oil (MMBbl)	13.2	5.5
NGLs (MMBbl)	23.0	11.0
Natural gas (Bcf)	498.1	348.3
Total proved developed producing reserves (Bcfe)	715.5	447.7
Proved developed non-producing:		
Oil (MMBbl)	0.5	0.5
NGLs (MMBbl)	0.8	0.6
Natural gas (Bcf)	22.3	12.3
Total proved developed non-producing reserves (Bcfe)	30.0	18.4
Total proved undeveloped:		
Oil (MMBbl)	6.5	10.9
NGLs (MMBbl)	17.2	13.4
Natural gas (Bcf)	469.4	227.5
Total proved undeveloped reserves (Bcfe)	611.7	373.2
Percent developed	54.9 %	55.5 %

(1) 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 12 months of $94.99 per Bbl for oil and (b) Henry Hub spot market prices for the prior 12 months of $4.35 per MMbtu for natural gas.
(2) Data for December 31, 2013 is based on the unweighted average of the first-day-of-the-month (a) West Texas Intermediate posted prices for the prior 12 months of $96.78 per Bbl for oil and (b) Henry Hub spot market prices for the prior 12 months of $3.67 per MMbtu for natural gas.
(3) The additional information regarding our estimates of proved reserves relate only to those associated with the Sabine O&G Properties at December 31, 2013.

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, 2013 and December 31, 2014. 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.

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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.

Barrett Frizzell, Vice President—Corporate Engineering, is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Frizzell is a graduate of Montana Tech with a Bachelor of Science degree in Petroleum Engineering. Mr. Frizzell has 15 years of energy experience and our geoscience 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.

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

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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, 2014
As of December 31, 2014, our proved undeveloped reserves totaled 6 MMBbls of oil, 17 MMBbls of NGLs and 469 Bcf of natural gas, for a total of 612 Bcfe. There were a total of 121 PUDs booked with 93, 14, 8, 3 and 3 wells booked in the Cotton Valley Sand, Granite Wash, Haynesville Shale, Eagle Ford and Pettet formations, respectively.

Changes in PUDs that occurred during 2014 were primarily due to:

- additions of 129,105 MMcfe attributable to historical Forest properties as a result of the Combination and two other acquisitions;
- additions of 161,717 MMcfe attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;
- the conversion of approximately 44,168 MMcfe attributable to PUDs into proved developed reserves net of revisions; and
- negative revisions of approximately 8,146 MMcfe in PUDs due to a combination of adjustments in PUD working interest, performance revisions and pricing.

Costs incurred relating to the development of PUDs were approximately $149 million during the twelve months ended December 31, 2014.

As of December 31, 2014, 2% of our total proved reserves were classified as proved developed non-producing.

Productive Wells

Our principal properties consist of developed and undeveloped oil and natural gas leases in the operating areas described above and the reserves associated with these leases. Generally, developed oil and natural gas leases remain in force as long as production is maintained. Undeveloped oil and natural gas leaseholds are generally for a primary term of three to five years. In most cases, the terms of our undeveloped leases can be extended by paying delay rentals or by producing oil and natural gas reserves that are discovered under those leases. The following table sets forth the number of productive wells in which we owned a working interest at December 31, 2014. Productive wells consist of producing wells identified as proved developed producing (“PDP”) per the December 31, 2014 reserve report prepared by Ryder Scott. 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. Approximately 73% of future net revenue associated with our properties is from natural gas while the remaining 27% is from oil and NGLs.

	Oil		Gas	
	Gross Wells	Net Wells	Gross Wells	Net Wells
East Texas	36	24	1,255	1,030
South Texas	153	95	18	17
North Texas	34	21	2	—
Total	223	140	1,275	1,047

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

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produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a 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,					
	2014 (1)		2013 (2)		2012 (2)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (3)	0.0	0.0	2.0	1.3	3.0	2.5
Dry	0.0	0.0	—	—	—	—
Total Exploratory	0.0	0.0	2.0	1.3	3.0	2.5
Development Wells:						
Productive (3)	65.0	49.1	43.0	30.8	7.0	7.0
Dry	0.0	0.0	1.0	0.4	—	—
Total Development	65.0	49.1	44.0	31.2	7.0	7.0
Total Wells:						
Productive (3)	65.0	49.1	45.0	32.1	10.0	9.5
Dry	0.0	0.0	1.0	0.4	—	—
Total	65.0	49.1	46.0	32.5	10.0	9.5

(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 years ended December 31, 2013 and December 31, 2012 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, 2014:

	Developed acreage		Undeveloped acreage		Total acreage		HBP	
	Gross	Net	Gross	Net	Gross	Net	%	
East Texas	216,080	179,386	62,413	39,769	278,493	219,155	82	%
South Texas	60,221	34,675	27,832	24,067	88,053	58,742	59	%
North Texas	8,140	4,621	43,242	32,231	51,382	36,852	13	%
Total Acreage	284,441	218,682	133,487	96,067	417,928	314,749	82	%

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, 2014 that will expire in 2015, 2016 and 2017 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.

	2015	2016	2017	Total
East Texas(1)	17,889	7,454	1,566	26,909
South Texas	27,250	13,454	4,836	45,540
North Texas	4,281	2,040	—	6,321
Total	49,420	22,948	6,402	78,770

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, 2014, 2013 and 2012. 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,		
	2014 (1)	2013 (2)	2012 (2)
Oil, NGLs and natural gas sales by product (in thousands):			
Oil	$ 181,313	$ 132,513	$ 30,343
NGL	62,420	59,772	36,957
Natural gas	218,630	161,938	110,122
Total	$ 462,363	$ 354,223	$ 177,422
Production data:			
Oil (MBbl)	2,169.52	1,403.62	317.07
NGL (MBbl))	2,120.56	1,842.47	931.26
Natural gas (Bcf)	49.22	44.29	41.12
Combined (Bcfe) (3)	74.96	63.77	48.61
Average prices before effects of economic hedges (4):			
Oil (per Bbl)	$ 83.57	$ 94.41	$ 95.70
NGL (per Bbl)	$ 29.44	$ 32.44	$ 39.68
Natural gas (per Mcf)	$ 4.44	$ 3.66	$ 2.68
Combined (per Mcfe) (3)	$ 6.17	$ 5.55	$ 3.65
Average realized prices after effects of economic hedges (4):			
Oil (per Bbl)	$ 81.79	$ 90.59	$ 95.79
NGL (per Bbl)	$ 29.44	$ 32.44	$ 39.68
Natural gas (per Mcf)	$ 4.30	$ 4.82	$ 5.17
Combined (per Mcfe) (3)	$ 6.02	$ 6.28	$ 5.81
Average costs (per Mcfe) (3):			
Lease operating expenses	$ 0.68	$ 0.70	$ 0.90
Marketing, gathering, transportation and other	$ 0.32	$ 0.28	$ 0.36
Production and ad valorem taxes	$ 0.24	$ 0.28	$ 0.09
General and administrative expenses	$ 0.41	$ 0.43	$ 0.44
Depletion, depreciation and amortization	$ 2.53	$ 2.15	$ 1.88

(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 years ended December 31, 2013 and December 31, 2012 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.

Risk Management

We have designed a risk management strategy using derivative instruments in an attempt to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the effect it could have on our operations and our ability to finance our capital budget and operations. Our decision on the quantity and price at which we choose to hedge our production is based on our view of existing and forecasted production volumes, budgeted drilling projects and current and future market conditions. While there are many different types of derivatives available, we typically use oil and natural gas price collars and swap agreements to attempt to manage price risk more effectively. The collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. Periodically, we may pay a fixed premium to increase the floor price above the existing market value at the time we enter into the arrangement. All collar agreements provide for payments to

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counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of oil and natural gas for the period is greater or less than the fixed price established for that period when the swap is put in place. Additionally, we have purchased natural gas puts and sold oil and natural gas calls. For the oil and natural gas calls, the counterparty has the option to purchase a set volume of the contracted commodity at a contracted price on a contracted date in the future. For the purchased and sold natural gas puts, the counterparty (sold) or we (purchased) have the option to sell a contracted volume of the commodity at a contracted price on a contracted date in future.

We enter into derivatives arrangements only with counterparties within the Second Amended and Restated Credit Agreement, dated as of December 16, 2014, a $2,000,000,000 reserve based revolving credit facility with an initial borrowing base of $1,000,000,000 (the "New Revolving Credit Facility"), which amended and restated the Amended and Restated Credit Agreement, dated as of April 28, 2009, maturing on April 7, 2016, 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"). The New Revolving Credit Facility allows us to hedge up to 100% of current production for 24 months, 75% of current production for months 25 through 36, and 50% of current production for months 37 through 60. For this purpose, "current production" refers to our latest monthly production total. For additional information on our hedging position, see "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Commodity Hedging Activities."

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.

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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 60% of our residue under NAESB contracts on a year to year term ending October 31, 2015 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 N. Shiner NGL's are sold under a five year gathering and processing agreement. We sell all our STX residue under NAESB contracts on a year-to-year term ending October 31, 2015. In South Texas, our oil is sold to various 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, 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. During the year ended December 31, 2012, purchases by four companies exceeded 10% of our total oil, NGLs and natural gas sales. Purchases by Enbridge Pipeline (East Texas) LP, Shell Trading (US) Company, Texla Energy Management LLC and Eastex Crude Company accounted for approximately 17%, 14%, 13% and 12% 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.

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

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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 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

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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

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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 regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies, issue regulations to implement and enforce these laws, 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, as well as the issuance of injunctions limiting or prohibiting our activities. 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.

Environmental regulatory programs typically regulate the permitting, construction and operations of a facility. Many factors can materially impact the ability to secure an environmental construction or operation permit. Enforcement actions brought by a regulatory agency can include significant civil penalties for regulatory violations regardless of intent and, under some circumstances, a regulatory agency can request an injunction prohibiting operations. In addition, in some cases private individuals can bring causes of action in court regarding compliance with environmental laws and regulations. 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 imposition of more stringent requirements 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, 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.

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The following is a summary of select existing environmental and occupational health and safety laws, as amended from time to time, to which our business operations are 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, 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. 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 classes of persons 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 if such wastes are determined to have hazardous characteristics.

We currently own, lease, operate and/or have acquired 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 certain surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. 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.

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 wellbore. 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 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 federal Safe Drinking Water Act ("SDWA") involving the use of diesel fuels and 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 the resultant proposed rule is expected in 2015.

On May 24, 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed 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, to date, no further action has been taken.

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 has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report concerning the potential impacts of hydraulic fracturing on drinking water resources is expected to be released sometime in the first half of 2015. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by early 2015. 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.

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 Underground Injection Control ("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 of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. In response to these concerns, regulators in some states are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") on October 28,

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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 be 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, the EPA has issued final rules under the Clean Air Act 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 addition, the EPA has announced that it will issue new regulations in the summer of 2015 to reduce methane emissions from new and modified sources in the oil and natural gas sector by up to 45 percent below 2012 levels by 2025. These standards, 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

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natural gas production facilities on an annual basis, which includes certain of our operations. Further, the EPA recently proposed a rule that would require 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.

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, including migratory birds. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered 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 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. 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 on-going 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.

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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 materially 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, 2014, we had 289 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.

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 annual, quarterly and current reports, proxy statements and 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.

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.

Risks Relating to Our Business

Due to our substantial liquidity concerns, we may be unable to continue as a going concern.

Our existing and future debt agreements could create issues as interest payments become due and the debt matures that will threaten our ability to continue as a going concern. For example, absent any action with respect to the repayment or refinancing of our existing indebtedness or any waivers or amendments to the agreements governing our existing indebtedness, our Term Loan will mature on November 16, 2016 and our New Revolving Credit Facility will mature on April 7, 2016. Additionally, the borrowing base under our New Revolving Credit Facility is subject to at least semi-annual redetermination and as a result, availability thereunder could be reduced and advances in excess of the new availability would need to be repaid. We also have substantial interest payments due during the next twelve months on our 2017 Notes and Legacy Forest Notes. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the debt agreements governing our indebtedness, an event of default could result, which would permit acceleration of such debt and which could result in an event of default under and acceleration of our other debt and could permit our secured lenders to foreclose on any of our assets securing such debt. Any accelerated debt would become immediately due and payable. While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or otherwise extend the maturity dates, and to cure any potential defaults, there is no assurance that any particular actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our existing and future debt agreements will be sufficient. The uncertainty associated with our ability to repay our outstanding debt obligations as they become due raises substantial doubt about our ability to continue as a going concern.

The report of our independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2014 contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern. As a result, we are in default under our New Revolving Credit Facility and Term Loan Facility.

Our New Revolving Credit Facility and Term Loan Facility require that our annual financial statements include a report from our independent registered public accounting firm with an unqualified opinion without an explanatory paragraph as to going concern. In consideration of the uncertainty mentioned above, the report of our independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2014 contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern. As a result, we are in default under our New Revolving Credit Facility and Term Loan Facility. We are currently in discussions with the lenders under our New Revolving Credit Facility regarding a waiver of this requirement. If we do not obtain a waiver of this requirement under within 30 days, there will exist an event of default under the New Revolving Credit Facility and the lenders under the New Revolving Credit Facility will be able to accelerate the debt. Similarly, if we do not obtain a waiver under the Term Loan Facility within 180 days, there will exist an event of default under the Term Loan Facility and the lenders under the Term Loan Facility will be able to accelerate the debt. Any acceleration of the debt obligations under the New Revolving Credit Facility or Term

Loan Facility would result in a cross-default and potential acceleration of the maturity of our other outstanding debt obligations. Therefore, all our outstanding debt obligations in the amount of $2.0 billion (net of discount) are presented in current liabilities as of December 31, 2014. Additionally, the lenders under the Term Loan Facility are subject to a 180-day standstill before they are able to exercise remedies as a result of the uncured event of default. Following the expiration of the 180-day standstill, the lenders are permitted to foreclose on the collateral securing the Term Loan Facility.

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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 2014 ranged from a high of $8.15 to a low of $2.74 per MMbtu and the NYMEX oil prices during 2014 ranged from a high of $107.95 to a low of $53.45 per Bbl. Thus far in 2015, commodity prices have continued to be depressed and volatile, with NYMEX natural gas prices ranging from a high of $3.32 to a low of $2.62 per MMbtu and the NYMEX oil prices ranging from a high of $53.56 to a low of $43.93 per Bbl through March 15, 2015. This price volatility also affects the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

The recent decreases in oil and gas prices have adversely affected our revenues, net income, cash flow and proved 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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Due to reduced commodity prices and lower operating cash flows, coupled with substantial interest payments, we may be unable to maintain adequate liquidity and our ability to make interest payments in respect of our indebtedness could be adversely affected.

Recent declines in commodity prices have caused a reduction in our available liquidity and we may not have the ability to generate sufficient cash flows from operations and, therefore, sufficient liquidity to meet our anticipated working capital, debt service and other liquidity needs. We are currently evaluating strategic alternatives to address our liquidity issues and high debt levels. We cannot assure you that any of these efforts will be successful or will result in cost reductions or additional cash flows or the timing of any such cost reductions or additional cash flows. In order to increase our liquidity to levels sufficient to meet our commitments, we are currently pursuing or considering a number of actions including (i) dispositions of non-core assets, (ii) actively managing our debt capital structure through a number of alternatives, including debt repurchases, debt- for-debt exchanges, debt-for-equity exchanges and secured financing, (iii) in- and out-of-court restructuring, (iv) minimizing our capital expenditures, (v) obtaining waivers or amendments from our lenders, (vi) effectively managing our working capital and (vii) improving our cash flows from operations. There can be no assurance that sufficient liquidity can be raised from one or more of these transactions or that these transactions can be consummated within the period needed to meet certain obligations. We cannot assure you that any refinancing or debt or equity restructuring would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all. Furthermore, we cannot assure you that any of our strategies will yield sufficient funds to meet our working capital or other liquidity needs, including for payments of interest and principal on our debt in the future, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations.

Our level of indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in our business or our industry and place us at a competitive disadvantage.

As of March 15, 2015, the total outstanding principal amount of our long-term indebtedness was $2.821 billion, consisting of indebtedness under the New Revolving Credit Facility, our 9.75% Senior Notes due 2017 (the “2017 Notes”), our 7.25% Senior Notes due 2019 (the “2019 Notes”) and our 7.50% Senior Notes due 2020 (the “2020 Notes” and, together with the 2019 Notes, the “Legacy Forest Notes”), and our $700 million term loan facility (as amended, the “Term Loan Facility”), and, as of March 15, 2015, no extensions of credit are available under the New Revolving Credit Facility after giving effect to $29 million of outstanding letters of credit.

If we do not generate sufficient cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans such as refinancing or restructuring our debt, selling assets, reducing or delaying scheduled expansions and capital investments, including planned drilling and completion activity, or seeking to raise additional capital.

We cannot assure you that we would be able to enter into these alternative financing plans on commercially reasonable terms or at all. However, any alternative financing plans that we undertake, if necessary, may not allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our business, results of operations, financial condition and business prospects, as well as our ability to satisfy our obligations in respect of the New Revolving Credit Facility, the 2017 Notes, the 2019 Notes, the 2020 Notes and the Term Loan Facility.

Our debt could have important consequences to you. For example, it could (i) increase our vulnerability to general adverse economic and industry conditions, (ii) 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, (iii) result in an event of default if we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the New Revolving Credit Facility, the indentures governing the 2017 Notes, the 2019 Notes and the 2020 Notes, the Term Loan Facility or other agreements governing our indebtedness, which event of default could result in all of our debt becoming immediately due and payable and could permit our lenders to foreclose on any of our assets securing such debt, (iv) increase our cost of borrowing, (v) restrict us from making strategic acquisitions or causing us to make non-strategic divestitures, (vi) limit our flexibility in planning for, or reacting to, changes in our

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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 and (vii) impair our ability to obtain additional financing in the future.

In addition, if we fail to comply with the covenants or other terms of any agreements governing our debt, our lenders may have the right to accelerate the maturity of that debt and foreclose upon the collateral securing that debt. Such an occurrence would adversely affect our financial condition.

The borrowing base under the New Revolving Credit Facility may be reduced by our lenders, and we may be required to repay a portion of the borrowings under the New Revolving Credit Facility.

The New Revolving Credit Facility limits the amounts we can borrow up to the lesser of the committed amount and a borrowing base amount, which is subject to redeterminations by the lenders semi-annually each April 1 and October 1, beginning April 1, 2015 or such later time as we may agree upon request of the administrative agent, or as the majority lenders may agree upon our request. We and the lenders comprising two-thirds of the lenders as measured by exposure may each request two unscheduled borrowing base redeterminations during any 12-month period. The borrowing base under the New Revolving Credit Facility could increase or decrease in connection with a redetermination with increases being subject to the approval of all lenders and decreases (and redeterminations maintaining the borrowing base) being subject to the approval of two-thirds of the lenders as measured by exposure. If the prices for oil and natural gas remain weak or deteriorate, if we have a downward revision in estimates of our proved reserves, or if we sell oil and natural gas reserves, our borrowing base may be reduced. The borrowing base is also subject to reduction as a result of certain issuances of additional debt, certain asset sales, cancellation of certain hedging positions or lack of sufficient title information. Based on discussions with the lenders under our New Revolving Credit Facility, we believe that our borrowing base may be decreased significantly in April 2015. Because our New Revolving Credit Facility is fully drawn, any decrease in our borrowing base as a result of the redetermination will result in a deficiency which must be repaid within 30 days or in six monthly installments thereafter, at our election. We may not have the financial resources in the future to make any mandatory deficiency principal prepayments required under our New Revolving Credit Facility, which could result in an event of default. Additionally, failure to make any mandatory deficiency principal payment under our New Revolving Credit Facility may result in a cross-default under our Term Loan Facility and certain of our senior notes.

Our substantial indebtedness, liquidity issues and the potential for restructuring transactions may impact our business, financial condition and operations.

Due to our substantial indebtedness, liquidity issues and the potential for restructuring, there is risk that, among other things:

- third parties' confidence in our ability to explore and produce oil and natural gas could erode, which could impact our ability to execute on our business strategy;
- it may become more difficult to retain, attract or replace key employees;
- employees could be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, hedge counterparties, vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us.

The occurrence of certain of these events has already negatively affected our business and may have a material adverse effect on our business, results of operations and financial condition.

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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. While we believe these allegations against us are without merit, if we are not successful in our defense of the Complaint, we may be required to purchase the holders of the 2019 Notes, and may not have sufficient liquidity to fund such purchase. If the court determines we are in default under the indenture governing the 2019 Notes, a cross default and acceleration under our other debt agreements may result, which would have a material adverse effect on our financial condition.

Our debt ratings were recently downgraded. This recent downgrade could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings, hedging arrangements and trade credit and the terms of any financings, hedging arrangements or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. Our debt ratings were recently downgraded. Additionally, we cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will be further lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. Our recent ratings downgrade and any future downgrade could adversely impact our ability to access financings, hedging arrangements or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions.

The New Revolving Credit Facility, the Term Loan Facility and the indentures governing the 2017 Notes, the 2019 Notes and the 2020 Notes contain a number of significant covenants in addition to covenants restricting the incurrence of certain kinds of additional debt. For example, the New Revolving Credit Facility requires us, among other things, to maintain a financial maintenance ratio in the form of a first lien secured leverage ratio not to exceed 3.0 to 1.0 commencing with the period ending March 31, 2015. These restrictions also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing the 2017 Notes, the 2019 Notes and the 2020 Notes, our Term Loan Facility and our New Revolving Credit Facility impose on us. In addition, complying with these covenants may also cause us to take actions that are not favorable to holders of our common stock and may make it more difficult for us to successfully execute our business strategy and compete against companies that are not subject to such restrictions.

The New Revolving Credit Facility, the Term Loan Facility and the indentures governing the 2017 Notes, the 2019 Notes and the 2020 Notes contain certain other covenants, including restrictions on our ability to create or incur liens, make dividends and other restricted payments, sell assets, engage in transactions with affiliates or merge or consolidate, in each case subject to certain carve-outs and exceptions. For more information regarding the existing debt agreements, please see "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

A breach of any covenant in our New Revolving Credit Facility, the Term Loan Facility, the indentures governing the 2017 Notes, the 2019 Notes and the 2020 Notes or other agreements governing any other indebtedness that we may incur from time to time would result in a default under such agreement after any applicable grace periods. The report of our independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2014 contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern. As a result, we are in default under our New Revolving Credit Facility and Term Loan Facility. A default, if not waived, could result in acceleration of the debt outstanding under the agreement and a default

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with respect to, and an acceleration of, the debt outstanding under other debt agreements. The accelerated debt would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such debt. Even if new financing were available at that time, it may not be on terms that are acceptable to us. If we are unable to repay the accelerated amounts, our creditors could proceed against the collateral granted to them to secure such debt. If our debt is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected.

We may be unable to maintain compliance with certain financial ratio covenants of our outstanding indebtedness which could result in an event of default that, if not cured or waived, would have a material adverse effect on our business, financial condition and results of operations.

Our New Revolving Credit Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. For example, the New Revolving Credit Facility requires us, among other things, to maintain a financial maintenance ratio in the form of a first lien secured leverage ratio not to exceed 3.0 to 1.0 commencing with the period ending March 31, 2015. As of December 31, 2014, we were in compliance with our financial covenants; however, we cannot guarantee that we will be able to comply with such terms at all times in the future. Any failure to comply with the conditions and covenants in our New Revolving Credit Facility that is not waived by our lenders or otherwise cured could lead to a termination of our New Revolving Credit Facility, acceleration of all amounts due under our New Revolving Credit Facility, or trigger cross-default provisions under other financing arrangements. These restrictions may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our indebtedness impose on us.

We failed to meet applicable New York Stock Exchange requirements following the Combination and as a result our stock was delisted from the New York Stock Exchange, which could adversely affect the market liquidity of our common stock and harm our businesses.

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 is now trading under the ticker symbol “SOGC.” 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 OTCQB 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.

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We may encounter difficulties in integrating Forest's business with our business and realizing the anticipated benefits of the Combination.

The Combination involved the combination of two companies which previously operated as independent companies. We have had to devote management attention and resources to integrating our business practices and operations. Potential difficulties we may encounter in the integration process include the following:

- the inability to successfully integrate the respective businesses of Forest and Sabine in a manner that permits us to achieve the cost savings and operating synergies anticipated to result from the Combination, which could result in the anticipated benefits of the Combination not being realized partly or wholly in the time frame currently anticipated or at all;
- lost sales and customers as a result of certain customers of either or both of the two companies deciding not to do business with us, or deciding to decrease their amount of business in order to reduce their reliance on a single company;
- integrating personnel from the two companies while maintaining focus on providing consistent, high quality products and services;
- preserving significant business relationships;
- consolidating corporate and administrative functions;
- potential unknown liabilities and unforeseen increased expenses, delays or regulatory conditions associated with the Combination;
- conforming standards, controls, procedures and policies, business cultures and compensation structures between Forest and Sabine O&G;
- retaining key employees;
- changes in estimates or errors impacting purchase accounting and the financial statements; and
- performance shortfalls as a result of the diversion of management's attention caused by completing the merger and integrating the companies' operations.

We expect to incur substantial expenses related to the integration of Forest's business with our business.

We expect to incur substantial expenses in connection with integrating the respective businesses, policies, procedures, operations, technologies and systems of Forest and Sabine. There are a large number of systems that must be integrated, including information management, purchasing, accounting and finance, sales, billing, payroll and benefits, fixed asset and lease administration and regulatory compliance. There are a number of factors beyond our control that could affect the total amount or the timing of all of the expected integration expenses. These expenses could, particularly in the near term, reduce the savings that we expect to achieve from the elimination of duplicative expenses and the realization of economies of scale and cost savings related to the integration of the businesses following the completion of the merger. These integration expenses may result in us taking significant charges against earnings now that the Combination has been completed.

Business issues historically faced by one company may be imputed to the operations of the other company.

To the extent that either we or Forest had or were perceived by customers to have had operational challenges, those challenges may raise concerns by customers of the other company now that the Combination has been completed, which may limit or impede our future ability to obtain additional work from those customers.

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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.

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 12 months. For the 12-months ended December 31, 2014, average prices used to calculate our estimated proved reserves and estimated discounted future net cash flows from proved reserves were $94.99 per Bbl for crude oil and $4.35 per MMbtu for natural gas. Commodity prices declined significantly in the fourth quarter of 2014 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, 2014. This could result in our having to remove non-economic reserves from our proved reserves in future periods.

Holding all other factors constant, if March SEC pricing of $82.72 per Bbl for crude oil and $3.88 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, 2014 would decrease by approximately $363 million, or 21%.

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

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· 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.

Our business requires substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves and production.

The oil and natural gas industry is capital intensive. During the years ended December 31, 2014 and 2013, we incurred approximately $562 million and $431 million in capital expenditures (excluding acquisitions and divestitures), respectively, and our full year capital expenditure forecast for 2015 is expected to total between approximately $230 million to $275 million (excluding acquisitions and divestitures). Additionally, prior to the completion of the Combination on December 16, 2014, Forest had incurred approximately $245 million in capital expenditures for property exploration, development and leasehold acquisitions in 2014 and $350 million during the year ended December 31, 2013.

We expect to continue to make substantial capital expenditures for the acquisition, development and production of oil and natural gas reserves. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive development.

To date, we have financed our capital expenditures primarily with capital contributions by our equity sponsors (for periods prior to the Combination), proceeds from bank borrowings, cash generated by operations and net proceeds from the sale of the 2017 Notes. We intend to finance future capital expenditures through, among other things, cash on hand, cash flow from operations, borrowings under the New Revolving Credit Facility to the extent we repay current borrowings, the issuance of debt or equity securities and the sale of assets. Our cash flow from operations and access to capital are subject to a number of variables, including:

· our proved reserves;
· the level of oil and natural gas we are able to produce from existing wells;
· the prices at which we are able to sell oil, natural gas and NGLs;
· the costs of developing and producing our oil and natural gas reserves;
· our ability to acquire, locate and produce new reserves;
· global credit and securities markets; and
· the ability and willingness of lenders and investors to provide capital and the cost of that capital.

If our cash flows or the borrowing base under the New Revolving Credit Facility decrease as a result of lower oil, natural gas and NGLs prices, operating difficulties, declines in reserves or for any other reason, we may be required to seek additional debt or equity financing to fund our operations and capital expenditures. Our Term Loan Facility, the New Revolving Credit Facility and the indentures governing the 2017 Notes, the 2019 Notes and the 2020 Notes restrict our ability to obtain certain kinds of new financing, and we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If we are unable to secure sufficient capital to meet our capital requirements, we may be required to curtail operations, which could lead to a possible loss of properties and an adverse impact on our oil and natural gas reserves, production, revenues and results of operations.

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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;
- 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, 2014 assumed that capital costs of approximately $1.073 billion 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.

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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. Our insurance program includes the following coverage:

· Commercial general liability covering:
o bodily injury and property damage;
o advertising injury and personal injury;
o production and completed operations;
o medical expenses; and
o underground resources and equipment property damage;
· Business automobile covering:
o liability on all autos, including owned, hired and non-owned vehicles;
· Claims made pollution liability covering:
o sudden and accidental and gradual seepage pollution events; and
o on-site cleanup;
· Workers' compensation and employer's liability covering statutory coverage in all states in which we operate;
· Umbrella and excess liability;
· Property and equipment;
· Crime; and
· Control of covering:
o cost of well control;
o pollution clean-up and debris removal;
o restoration and redrill; and
o care, custody and control.

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 materially 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.

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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. For example, during 2012, 2013 and 2014 we incurred a ceiling test write-down of $641.8 million, zero and $247.7 million, 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, 2014, 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, as of December 31, 2014, the unweighted average of the historical first day of the month pricing for the previous twelve months of oil and natural gas were $94.99 per Bbl and $4.35 per MMbtu, respectively, compared to $82.72 per Bbl and $3.88 per MMbtu for oil and natural gas, respectively, in March 2015. Holding all other factors constant, if commodity prices used in our year-end reserve estimates were decreased by $12.27 per Bbl for crude oil and $0.47 per Mcf for natural gas, thereby approximating the pricing environment existing in March 2015, our estimated discounted future cash flows from proved reserves at December 31, 2014 would decrease by approximately $363 million, or 21%.

In connection with certain audits and reviews of Sabine O&G's financial statements in prior years, our independent registered public accounting firm identified and reported misstatements to management. Certain of such misstatements were deemed to be the result of internal control deficiencies that constituted material weaknesses in our internal control over financial reporting. In addition, Forest's management concluded that certain material weaknesses existed in its internal control over financial reporting as of December 31, 2013. If one or more material weaknesses recur or if we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

Sabine O&G restated its financial statements for the years ended December 31, 2012 and 2011 with respect to the accounting and disclosures for certain derivative financial transactions in both the 2012 and 2011 periods and with respect to reversing a bargain purchase gain recognized for the acquisition of certain oil and natural gas properties in 2012. Sabine O&G concluded that these restatements constituted material weaknesses in internal control over financial reporting. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

Additionally, Forest previouslyconcluded that material weaknesses existed in its internal control over financial reporting as of December 31, 2013 with respect to certain information technology general controls, controls over division of interests and controls associated with inputs to the ceiling limitation test. Our management is in the process of reviewing the remediation of controls over these processes and has not reached a conclusion regarding the effectiveness of such remediation. We anticipate complying with Section 404 certification and attestation requirements for the year ended December 31, 2015.

Our efforts to develop and maintain internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future. Further, our remediation efforts may not

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enable us to remedy or avoid material weaknesses or significant deficiencies in the future. Any failure to remediate deficiencies and to develop or maintain effective controls, or any difficulties encountered in our implementation or improvement of our internal control over financial reporting could result in material misstatements that are not prevented or detected on a timely basis.

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.

During the last several years, economic uncertainty for the global economy has arisen due to concerns relating to the global financial crisis, including the mortgage and real estate markets in the United States, high levels of unemployment in the United States, increased levels of sovereign and individual debt, energy costs, geopolitical issues and the availability and cost of credit. In addition, 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 may have 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, 2014 in the Eagle Ford Shale in South Texas and the Granite Wash in North Texas, we drilled 36 gross (27.0 net) and 19 gross (12.3 net) wells and completed 42 gross (32.2 net) and 18 gross (11.2 net) wells, respectively, and, prior to the Combination, Forest drilled a total of 18 gross (16.3 net) wells relating to their properties during the same year. 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

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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.

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;

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- taxation; 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 liabilities under 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 and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages, as well 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 that 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 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.

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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 wellbore. 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. 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 the resultant proposed rule is expected in 2015. More recently, on May 24, 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed 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, to date, no further action has been taken.

In addition, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. 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 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. 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 has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources is expected to be released sometime in the first half of 2015. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by early 2015. 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.

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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 proposed a rule that would require 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.

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.

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

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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 27% of our core net leasehold acreage was undeveloped as of December 31, 2014, 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, 2014, approximately 27% 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 45% of our total estimated proved reserves at December 31, 2014 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.

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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.

Our hedging activities could result in financial losses or could reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, we currently enter into hedging arrangements for a portion of our oil and natural gas production and may in the future enter into such arrangements for portions of our oil and natural gas production. These hedging arrangements expose us to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these types of hedging arrangements limit the benefit we would receive from increases in the prices for natural gas or oil and may expose us to cash margin requirements.

Our counterparties are typically financial institutions who are lenders under our New Revolving Credit Facility. The risk that a counterparty may default on its obligations is heightened by the recent financial sector crisis and other losses incurred by many banks and other financial institutions, including our counterparties or their affiliates. These losses may affect the ability of the counterparties to meet their obligations to us on hedge transactions, which would reduce our revenues from hedges at a time when we are also receiving a lower price for our oil and natural gas sales, thus triggering the hedge payments. As a result, our operations, liquidity and financial condition could be materially, adversely affected.

Our commodity price risk management activities could have the effect of reducing our net income. At December 31, 2014, the net unrealized gain represented by our commodity price risk management contracts was $153.3 million, but in the past we have incurred significant unrealized losses in connection with our commodity price risk management contracts. In the future, we may continue to incur significant unrealized gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place. In addition, because of the recent decrease in commodity prices, it may become costlier for us to enter into hedging arrangements in the future than it has been historically, in more favorable commodity price environments.

Oil and natural gas prices are volatile. A substantial portion of our hedges are set to expire in 2015. If we choose not to replace hedges as those contracts expire, our cash flows from operations will be subjected to increased volatility.

We enter into hedging transactions of our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. A substantial portion of our hedges are set to expire in 2015. As our hedges expire, more of our future production will be sold at market prices, exposing us to the fluctuations in the price of oil and natural gas, unless we enter into additional hedging transactions. We may choose not to replace existing hedges as those contracts expire, which will subject our cash flows from operations to increased volatility.

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

Our principal exposures to credit risk are through receivables resulting from commodity derivatives instruments ($160.2 million at December 31, 2014), joint interest receivables ($22.6 million at December 31, 2014) and the sale of our oil, natural gas and NGLs production ($85.5 million in receivables at December 31, 2014), 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, principally with respect to hedging agreements but also insurance contracts and bank lending commitments. 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

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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, 2014, four customers accounted for approximately 47% 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.

The recent adoption of derivatives legislation by the U.S. 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.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production, and, in the future, we may enter into derivative contracts to hedge a portion of our exposure to fluctuations in interest rates. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which requires the SEC and the CFTC to promulgate rules and regulations implementing the new legislation. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could affect liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

The Dodd-Frank Act also may require the 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 full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations implementing the Dodd-Frank Act, the results of our 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 Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Any of these consequences could have a material adverse effect on us, our financial condition and the results of our 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 2015 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. 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.

Item 1B.Unresolved Staff Comments

There were no unresolved SEC staff comments at December 31, 2014.

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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.

Augenbaum v. Lone Pine Resources Inc. et al.

This claim was filed on May 25, 2012, as a purported class action in the Supreme Court of the State of New York, New York County against Forest, Lone Pine, certain of Lone Pine's current and former directors and officers (the "Individual Defendants"), and certain underwriters (the "Underwriter Defendants") of Lone Pine's initial public offering (the "IPO"), which was completed on June 1, 2011. The class action was subsequently removed to the United States District Court for the Southern District of New York. The complaint alleged that Lone Pine's registration statement and prospectus issued in connection with the IPO contained untrue statements of material fact or omitted to state material facts relating to forest fires that occurred in Northern Alberta in May 2011, the rupture of a third-party oil sales pipeline in Northern Alberta in April 2011, and the impact of those events on Lone Pine, that the alleged misstatements or omissions violated Section 11 of the Securities Act of 1933 (the "Securities Act"), and that Lone Pine, the Individual Defendants, and the Underwriter Defendants are liable for such violations. (The complaint was subsequently amended to drop the allegation regarding the forest fires.) The complaint further alleged that the Underwriter Defendants offered and sold Lone Pine's securities in violation of Section 12 (a) (2) of the Securities Act, and the putative class members sought rescission of the securities purchased in the IPO that they continued to own and rescissionary damages for securities that they had sold. Finally, the complaint asserted a claim against Forest under Section 15 of the Securities Act, alleging that Forest was a "control person" of Lone Pine at the time of the IPO. The complaint alleged that the putative class, which purchased shares of Lone Pine's common stock pursuant and/or traceable to Lone Pine's registration statement and prospectus, was damaged when the value of the stock declined in August 2011.

On March 26, 2014, the judge overseeing the lawsuit granted Defendants' motion to dismiss, with prejudice, for failure to state a claim upon which relief may be granted. Plaintiffs appealed the decision on April 28, 2014, and briefing was completed on August 5, 2014. Forest subsequently agreed to a settlement with the named plaintiff, all of which will be paid by Lone Pine's insurance carrier. The appeal was dismissed on December 3, 2014.

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

On November 11, 2013, Jefferson Parish filed suit against Forest 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. Forest tendered a claim for indemnity to Texas Petroleum Investment Company ("TPIC'), which TPIC rejected. Forest 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 has been on hold pending the court's decision regarding federal jurisdiction in a similar lawsuit. That lawsuit was recently remanded to Louisiana state court, so the parties have filed a motion to reopen this case and set a status conference. Plaintiffs seek unspecified monetary damages and restoration of the Jefferson Parish Coastal Zone to its original condition. This matter is in the very early stages of litigation.

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

On November 8, 2013, Plaquemines Parish filed suit against Forest 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. Forest 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. A motion to remand is scheduled to be heard in early 2015. Plaintiffs seek unspecified monetary damages and restoration of the Plaquemines Parish Coastal Zone to its original condition. This matter is in the very early stages of litigation.

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 Forest in the proceeding styled Forest Oil Corp., et al. v. El Rucio Land & Cattle Co., et al., which occurred in Harris County, Texas. 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 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 Forest, the trial court for the 55th Judicial District, in the District Court in 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. Forest filed a petition for review with the Texas Supreme Court on January 5, 2015.

We are a party to various other lawsuits, claims, and proceedings in the ordinary course of business. These proceedings are subject to uncertainties inherent in any litigation, and the outcome of these matters is inherently difficult to predict with any certainty. We believe that the amount of any potential loss associated with these proceedings would not be material to our consolidated financial position; however, in the event of an unfavorable outcome, the potential loss could have an adverse effect on our results of operations and cash flow.

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 Transactions, 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 Transactions. 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 Transactions arise 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 Transactions have 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 Transactions, 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 Transactions with certain inappropriate "deal protection devices" that impede Forest Oil from pursuing superior potential transactions with other bidders.

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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 Transactions or, in the alternative, rescission and/or rescissory and other damages in the event that the proposed Transactions are 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 Transactions, 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 Transactions. 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 Transactions or, in the alternative, rescission in the event the proposed Transactions are 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, will 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.

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 stockholders 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

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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 March 13, 2015, plaintiffs informed Sabine that they believe Sabine has materially violated the terms of the memorandum of understanding executed on November 11, 2014 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 and will respond to their letter in due course. If plaintiffs prevail in their position concerning the memorandum of understanding, the proposed settlement as contemplated by the memorandum of understanding may be terminated.

Wilmington Savings Fund Society, FSB v. Forest Oil Corporation

On February 26, 2015, we were served with a complaint concerning the indenture governing our 2019 Notes. The complaint is pending in the Supreme Court of the State of New York and generally alleges that certain events of default had occurred with respect to the 2019 Notes due to the business combination between Forest Oil Corporation and Sabine Oil & Gas LLC. We also received a notice of default and acceleration from the trustee with respect to the 2019 Notes containing similar allegations. If we are not successful in our defense of this complaint, we 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, and if the court determines we are in default under the indenture governing the 2019 Notes, a cross-default and acceleration under our other debt agreements may result. We believe these allegations against us are without merit and intend to vigorously defend against such claims and pursue any and all defenses available. However, we are unable to predict the outcome of such matter, and the proceedings may have a negative impact on our liquidity, financial condition and results of operations.

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.

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.

While we intend to vigorously defend the claims against us and believe they are without merit, an adverse ruling could cause our indebtedness to become immediately due and payable.

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 OTCQB under the symbol "SOGC." On March 15, 2015, there were 214,669,984 shares of our Common Stock outstanding held by 691 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 15, 2015, 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. There were no cash dividends declared on the Common Stock in 2013 or 2014. On March 15, 2015, the closing price of our Common Stock was $0.13. Our Common Stock's trading range during the periods indicated was as follows:

	Common Stock	
	High	Low
2013		
First Quarter	$ 7.44	$ 5.18
Second Quarter	5.43	3.77
Third Quarter	6.67	4.02
Fourth Quarter	6.52	3.43
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

Dividend Restrictions

Our present or future ability to pay dividends is governed by (i) the provisions of the New York Business Corporation Law, (ii) our Restated Certificate of Incorporation and Bylaws, (iii) the indentures governing the 2017 Notes, the 2019 Notes and the 2020 Notes, (iv) the Term Loan Facility and (v) the New Revolving Credit Facility. The provisions in the indentures pertaining to these senior notes, the Term Loan Facility and the New Revolving Credit Facility limit our ability to make restricted payments, which include dividend payments. 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 7. Long-Term Debt” and “Note 8. 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 (2) of the Securities Act as a transaction not involving a public offering. We did not make any other sales of unregistered equity securities during the quarter ended December 31, 2014.

The Series A preferred shares are convertible into our common shares at the option of Sabine Investor Holdings if (1) Sabine Investor Holdings is able to convert a portion of the Series A preferred shares into our common shares and, as a result of such conversion, would not, together with affiliates, hold more than 50% of our voting power and (2) our board of directors approves such conversion (such approval not to be unreasonably withheld). In addition, Series A preferred shares will convert automatically if Sabine Investor Holdings transfers such shares to a third party and such third party would not, together with its affiliates, hold more than 50% of our 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 our common shares as described in the preceding paragraph, each Series A preferred share will be convertible into 100 of our common shares. If our reincorporation from New York to Delaware (the "Reincorporation Merger") is not approved by holders of the requisite number of our shares at the first special meeting of our shareholders held for such purpose, then from the date of such special meeting until the time at which the Reincorporation Merger is approved by our shareholders, the conversion ratio will be adjusted upwards such that, on an annualized basis, the adjustment results in the Series A preferred shares being convertible into an additional number of our common shares equal to 10% of the total number of our common shares underlying all of the then outstanding Series A preferred shares (assuming all such Series A preferred shares were then convertible into our common shares). The adjustment to the foregoing conversion ratio will be calculated quarterly.

Issuer Purchases of Equity Securities

We did not purchase any of our equity securities during the fourth quarter of 2014.

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Stock Performance Graph

The following graph compares the cumulative total shareholder return on our Common Stock during the five years ended December 31, 2014 with the cumulative total shareholder return of the Russell 2000 Index, the Standard & Poors 500 Index, the Dow Jones U.S. Select Oil Exploration & Production Index (DJSOEP), and the State Street SPDR of the Standard & Poors Oil & Gas Exploration & Production Select Industry Index ("XOP"), of which the ten largest weighted company holdings as of March 27, 2015 are SandRidge Energy Incorporated, Energy XXI Ltd., SM Energy Company, Range Resources Corporation, Laredo Petroleum Incorporated, EXCO Resources Incorporated, Rice Energy Incorporated, California Resources Corporation, EP Energy Corporation, and Callon Petroleum Company. The comparison assumes an investment of $100 on December 31, 2009 in each of our Common Stock, the Russell 2000 Index and the XOP.

Comparison Of 5 Year Cumulative Total Return*
Among Sabine Oil & Gas Corporation, the Russell 2000, the S&P500, the DJSOEP and the XOP

*$100 invested on 12/31/09 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

The information in this Annual Report on Form 10-K appearing under the heading "Stock Performance Graph" is being furnished pursuant to Item 201 (e) of Regulation S-K and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201 (e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act.

In our annual report for the year ended December 31, 2013, we had prepared the Comparison of 5 Year Cumulative Total Return by comparing the cumulative total shareholder return on our common stock during the five years ended December 31, 2013 with the cumulative total shareholder return of the S&P 500 Index and the Dow Jones U.S. Exploration and Production Index. Given the significant decrease in our market capitalization since December 31, 2013, we believe a comparison to the Russell 2000 Index and the XOP, which are comprised of companies more similarly sized to us, is more meaningful to investors.

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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, 2014.

	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, 2013	—	—	20,000,000
Awarded	16,859,403	0.34	(16,859,403)
Vested	(2,871,173)	0.34	—
Forfeited	(65,000)	0.34	65,000
Unvested at December 31, 2014	13,923,230	0.34	3,205,597

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.

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Item 6. Selected Financial Data

The following selected historical financial and operating information was derived from Sabine's Consolidated Financial Statements as of and for the five years ended December 31, 2014. The selected financial data should be read in conjunction with the Company's Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements and Supplemental Information on Oil and Natural Gas Producing Activities in "Part I, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Part II, Item 8. Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands, except per share amounts)				(unaudited)
Total revenues	$ 464,723	$ 354,978	$ 177,446	$ 201,552	$ 133,452
Total operating expenses	762,566	246,656	843,627	58,182	108,700
Total other income (expenses)	6,110	(97,745)	(20,618)	31,813	69,544
Net income (loss) before taxes	(291,733)	10,577	(686,799)	175,183	94,296
Income tax expense	34,987	—	—	—	—
Total operating income (loss) including noncontrolling interests	(326,720)	10,577	(686,799)	175,183	94,296
Less: Net income (loss) applicable to noncontrolling interest	—	—	17	(117)	(260)
Net income (loss) applicable to controlling interests	(326,720)	10,577	(686,782)	175,066	94,036
Net income (loss) per share (1)					
Basic	$ (2.67)	$ 0.09	$ (6.92)	$ 2.01	$ 1.14
Diluted	$ (2.67)	$ 0.09	$ (6.92)	$ 2.01	$ 1.14
Weighted average shares outstanding – basic	122,237	118,863	99,179	87,084	82,570
Weighted average shares outstanding – diluted	122,237	118,863	99,179	87,084	82,570
Balance Sheet Data					
Cash and cash equivalents	$ 3,252	$ 11,821	$ 6,193	$ 4,306	$ 4,437
Total property, plant and equipment, net	2,066,068	1,380,042	1,256,210	1,351,815	648,044
Total Assets	2,438,350	1,678,719	1,560,559	1,529,069	801,552
Debt, net of discount	1,988,883	1,243,312	1,242,538	764,782	440,153
Total shareholders' (deficit) equity	(63,792)	201,010	200,433	624,128	247,207
Total liabilities and shareholders' (deficit) equity	2,438,350	1,678,719	1,560,559	1,529,069	801,552
Cash Flow Data					
Cash flows provided by operating activities	209,201	217,198	144,166	159,032	105,715
Cash flows used in investing activities	(438,614)	(193,809)	(687,385)	(680,922)	(325,389)

Cash flows provided by (used in) financing activities	220,844	(17,761)	545,106	521,759	221,622
Other Financial Data					
Adjusted EBITDA	330,880	296,057	194,986	194,272	129,222

(1) 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 to reflect the legal capital of the accounting acquiree. Beginning on December 16, 2014, common shares are presented for the combined company.

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	For the Year Ended December 31,				
	2014	2013	2012	2011	2010 (unaudited)
Reconciliation of consolidated net income (loss) to Adjusted EBITDA					
Net income (loss) applicable to controlling interests	$ (326,720)	$ 10,577	$ (686,782)	$ 175,066	$ 94,036
Adjustments to derive adjusted EBITDA					
Interest, net of capitalized interest	115,586	99,471	49,387	39,632	33,468
Depletion, depreciation and amortization	189,516	137,068	91,353	75,424	47,547
Impairments	423,092	1,125	664,438	4,192	1,711
Gain on bargain purchase	—	—	—	(99,548)	(372)
Other	25,974	1,739	599	439	1,156
Amortization of deferred rent	(72)	(249)	(532)	(406)	(320)
Accretion	958	952	862	628	493
Loss (gain) on derivative instruments	(120,848)	46,545	75,734	(1,272)	(51,996)
Option premium amortization	(11,593)	(1,171)	(56)	—	3,239
Income tax expense	34,987	—		—	—
Net income applicable to noncontrolling interests	—	—	(17)	117	260
Adjusted EBITDA	$ 330,880	$ 296,057	$ 194,986	$ 194,272	$ 129,222

	For the Year Ended December 31,				
	2014	2013	2012	2011	2010 (unaudited)
Reconciliation of net cash flows from operating activities to Adjusted EBITDA					
Net cash flow provided by operating activities	$ 209,201	$ 217,198	$ 144,166	$ 159,032	$ 105,715
Interest adjustments	94,976	79,556	42,995	35,357	17,190
Working capital and other adjustments	26,703	(697)	7,825	(117)	6,317
Adjusted EBITDA	$ 330,880	$ 296,057	$ 194,986	$ 194,272	$ 129,222

"Adjusted EBITDA" is a non-GAAP financial measure which Sabine uses in its business. This measure is not calculated or presented in accordance with US GAAP.

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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- the Term Loan Facility and the indenture governing the 2017 Notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness unless the ratio of adjusted consolidated EBITDA to adjusted consolidated interest expense and other fixed charges over the trailing four fiscal quarters will be at least 2.0 to 1.0 (subject to exceptions for borrowings within certain limits);
- the Legacy Forest Notes contain covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness unless the ratio of adjusted consolidated EBITDA to adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.25 to 1.00 (subject to exceptions within certain limits); and
- the New Revolving Credit Facility requires us to comply with a financial maintenance ratio in the form of a first lien secured leverage ratio not to exceed 3.0 to 1.0 which is defined as a ratio of consolidated first lien secured debt as of the last day of a fiscal quarter to adjusted EBITDA for the period of four fiscal quarters then ending.

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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, Haynesville Shale and Pettet formations;
- South Texas, targeting the Eagle Ford Shale formation; and
- North Texas, targeting the Granite Wash formation.

As of December 31, 2014, we held interests in approximately 278,500 gross (219,200 net) acres in East Texas, 88,100 gross (58,700 net) acres in South Texas and 51,400 gross (36,900 net) acres in North Texas. As of December 31, 2014, we were the operator on 89%, 99% and 99% of our net acreage positions in East Texas, South Texas and North Texas, respectively.

Our full year 2015 capital expenditures are forecasted to total approximately $230 million to $275 million. As a result, we expect production growth from our 2015 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.

We expect to focus operations in the exploration and production segment of the energy industry in the United States. Our gathering and processing assets are primarily dedicated to supporting the natural gas volumes we produce and do not generate any material amounts of revenue. Our ability to develop and produce current reserves and add additional reserves is driven by several factors, including:

- success in the drilling of new wells;
- commodity prices;
- the availability of attractive acquisition opportunities and our ability to execute them;
- the activities and elections of third parties under our joint development agreements;
- the availability of capital and the amount we invest in the leasing and development of properties and the drilling of wells;
- facility or equipment availability and unexpected delays or downtime, including delays imposed by or resulting from compliance with regulatory requirements; and

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· the rate at which production volumes naturally decline.

Ability to Continue as a Going Concern

We have significant pending maturities on our debt obligations. If we are unable to refinance our 2017 Notes to mature at least 91 days after December 31, 2018, our Term Loan Facility in an outstanding amount of $700 million will mature on November 16, 2016. Our New Revolving Credit Facility, which currently has $971 million of debt outstanding, will mature on April 7, 2016. Our ability to repay the principal amount of our debt upon the pending maturities has been negatively impacted by significant decreases in the market price for oil, natural gas, and NGLs during the fourth quarter of 2014 with continued weakness into the first quarter of 2015. Additionally, our borrowing base under our New Revolving Credit Facility is subject to its next semi-annual redetermination in April 2015. Based on discussions with the lenders under our New Revolving Credit Facility, we believe that our borrowing base may be decreased significantly. Because our New Revolving Credit Facility is fully drawn, any decrease in our borrowing base as a result of the redetermination will result in a deficiency which must be repaid within 30 days or in six monthly installments thereafter, at our election. The uncertainty associated with our ability to repay our outstanding debt obligations as they become due raises substantial doubt about our ability to continue as a going concern.

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 were 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. Following the Combination, our common stock trades on the OTCQB, currently 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 throughout the first quarter of 2015. If commodity prices remain at current levels, we expect significantly lower revenues and operating cash flows compared to historical results.

To achieve more predictable cash flows and to reduce exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of oil and natural gas production. We currently use a combination of fixed price oil and natural gas swaps and options for which we receive a fixed price (via either swap price, floor or collar or put price) for future production in exchange for a payment of the variable market price received at the time future production is sold. 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 $10.1 million, $6.6 million and $2.7 million for the years ended December 31, 2014, 2013 and 2012, respectively.

- Depletion, depreciation and amortization. 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, 2014, 2013 and 2012, we recorded $247.7 million, no impairment, and $641.8 million, 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, 2014, the unweighted average of the historical first day of the month pricing for oil and natural gas were $94.99 per Bbl and $4.35 per MMbtu, respectively, compared to $82.72 per Bbl and $3.88 per MMbtu for oil and natural gas, respectively, in March 2015. Holding all other factors constant, if commodity prices used in our year-end reserve estimates were decreased by $12.27 per Bbl for crude oil and $0.47 per Mcf for natural gas, thereby approximating the pricing environment existing in March 2015, our estimated discounted future cash flows from proved reserves at December 31, 2014 would decrease by approximately $363 million, or 21%. 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

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leasehold that can be associated with proved reserves, leasehold that expired in the quarter or leasehold that is not a part of our development strategy and will be abandoned.

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, 2014, 2013 and 2012, we recorded impairment charges for gas gathering and processing equipment of $1.7 million, no impairment, and $21.4 million, 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, 2014, 2013 and 2012, we recorded impairment charges for other assets of $0.2 million, $1.1 million and $1.2 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, 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.

- 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 15, 2015, the total outstanding principal amount of our long-term indebtedness was $2.821 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 15, 2015, no extensions of credit are available under the New Revolving Credit Facility. We will likely continue to incur significant interest expense as we continue to grow. To date, we have not entered into any interest rate hedging arrangements to mitigate the effects of interest rate changes. Additionally, we capitalized $6.5 million, $13.0 million and $4.3 million of interest expense for the years ended December 31, 2014, 2013 and 2012, respectively.
- 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 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.

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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 2012 through 2014:

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
North Texas – Granite Wash/Cleveland Sand (TX)	December 2012	$ 658
South Texas – Eagle Ford Shale (TX)	December 2012	$ 79

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 December 2013, we sold our working interest in approximately 27,000 net acres in the Texas Panhandle and surrounding Oklahoma areas for an adjusted purchase price of approximately $169 million. This includes primarily the Cleveland Sand assets acquired in 2012. In addition, we sold all of our oil and natural gas properties located in the Rocky Mountain region in the second quarter of 2012.

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Results of Operations

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 (loss) income before income taxes	$ (291,733)	$ 10,577	$ (302,310)		*
Income tax expense	34,987	—	34,987		*
Net (loss) income	$ (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			
(Gain) loss 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."

	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 (per Bbl)	$ 29.44	$ 32.44	$ (3)	(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 (per 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	$ 0.37	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,		Percent	
	2014	2013	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. 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. 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%, primarily 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 due to increased production without a proportionate increase in general and administrative expenses.

Depletion, depreciation and amortization. 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, 2012 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 the 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. The amount of future gain or loss recognized on derivative instruments is dependent upon future commodity prices, which will affect the value of the contracts.

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.

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The following table sets forth selected operating data for the year ended December 31, 2013 compared to the year ended December 31, 2012:

	For the Year Ended December 31, 2013	2012	Amount of Increase (Decrease)	Percent Change	
	(in thousands)				
Revenues					
Oil, natural gas liquids and natural gas	$ 354,223	$ 177,422	$ 176,801	100	%
Other	755	24	731		*
Total revenues	354,978	177,446	177,532	100	%
Operating expenses					
Lease operating	44,620	43,649	971	2	%
Marketing, gathering, transportation and other	17,567	17,491	76	0	%
Production and ad valorem taxes	17,824	4,400	13,424	305	%
General and administrative	27,469	21,434	6,035	28	%
Depletion, depreciation and amortization	137,068	91,353	45,715	50	%
Accretion	952	862	90	10	%
Impairments	1,125	664,438	(663,313)		*
Other operating expenses (income)	(858)	516	(1,374)		*
Total operating expenses	245,767	844,143	(598,376)	(71)	%
Other income (expenses)					
Interest, net of capitalized interest	(99,471)	(49,387)	50,084	101	%
Gain on derivative instruments	814	29,267	28,453		*
Other income	23	18	(5)		*
Total other expenses	(98,634)	(20,102)	78,532		*
Net income (loss), including noncontrolling interests	10,577	(686,799)	697,376		*
Less: Net income applicable to noncontrolling interests	—	17	(17)	(100)	%
Net income (loss) applicable to controlling interests	$ 10,577	$ (686,782)	$ 697,359		*
Reconciliation to derive Adjusted EBITDA (1):					
Interest, net of capitalized interest	99,471	49,387			
Depletion, depreciation and amortization	137,068	91,353			
Impairments	1,125	664,438			
Other	1,739	599			
Amortization of deferred rent	(249)	(532)			
Accretion	952	862			
Loss (gain) on derivative instruments	46,545	75,734			
Option premium amortization	(1,171)	(56)			
Net income applicable to noncontrolling interests	—	(17)			

Adjusted EBITDA (1)	$ 296,057	$ 194,986

* 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, 2013	2012	Amount of Increase (Decrease)	Percent Change	
Oil, NGL and natural gas sales by product (in thousands):					
Oil	$ 132,513	$ 30,343	102,170	337	%
NGL	59,772	36,957	22,815	62	%
Natural gas	161,938	110,122	51,816	47	%
Total	$ 354,223	$ 177,422	176,801	100	%
Production data:					
Oil (MBbl)	1,403.62	317.07	1,086.55	343	%
NGL (MBbl)	1,842.47	931.26	911.21	98	%
Natural gas (Bcf)	44.29	41.12	3.17	8	%
Combined (Bcfe) (1)	63.77	48.61	15.16	31	%
Average prices before effects of economic hedges (2):					
Oil (per Bbl)	$ 94.41	$ 95.70	(1.29)	(1)	%
NGL (Bbl)	$ 32.44	$ 39.68	(7.24)	(18)	%
Natural gas (per Mcf)	$ 3.66	$ 2.68	0.98	37	%
Combined (per Mcfe) (1)	$ 5.55	$ 3.65	1.90	52	%
Average realized prices after effects of economic hedges (2):					
Oil (per Bbl)	$ 90.49	$ 95.79	(5.30)	(6)	%
NGL (Bbl)	$ 32.44	$ 39.68	(7.24)	(18)	%
Natural gas (per Mcf)	$ 4.82	$ 5.17	(0.35)	(7)	%
Combined (per Mcfe) (1)	$ 6.28	$ 5.81	0.47	(8)	%
Average costs (per Mcfe) (1):					
Lease operating	$ 0.70	$ 0.90	(0.20)	(22)	%
Marketing, gathering, transportation and other	$ 0.28	$ 0.36	(0.08)	(22)	%
Production and ad valorem taxes	$ 0.28	$ 0.09	0.19	211	%
General and administrative	$ 0.43	$ 0.44	(0.01)	(2)	%
Depletion, depreciation and amortization	$ 2.15	$ 1.88	0.27	14	%

(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 $177.4 million in 2012 to $354.2 million in 2013, an increase of 100%. This increase of $176.8 million was primarily the result of an increase in liquids revenues of $125.0 million due to an increase in liquids production subsequent to our

North Texas and South Texas acquisitions and our active and successful development program in these regions contributing approximately $140.1 million, partially offset by decreased liquids pricing of approximately $15.2 million. Additionally, natural gas revenues increased $51.8 million, or 47%, due to an increase in realized natural gas prices of 37% contributing approximately $43.4 million, and increased natural gas production contributing approximately $8.5 million due to acquisitions in North Texas and South Texas and the successful development programs in these regions, partially offset by lower East Texas volumes and the sale of the Rockies assets.

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The following table sets forth additional information concerning our production volumes for the year ended December 31, 2013 compared to the year ended December 31, 2012:

	For the Year Ended December 31,		Percent Change	
	2013	2012		
	(in Bcfe)			
South Texas	9.89	0.38	2,508	%
East Texas	42.05	45.83	(8)	%
North Texas	11.83	0.54	2,091	%
Rockies (through August 31, 2012)	—	1.86	(100)	%
Total	63.77	48.61	31	%

Lease operating expenses. Lease operating expenses increased from $43.6 million in 2012 to $44.6 million in 2013, an increase of 2%. The increase in lease operating expense of $1.0 million is primarily due to our December 2012 acquired properties. Lease operating expenses decreased from $0.90 per Mcfe in 2012 to $0.70 per Mcfe in 2013. The decrease of $0.20 per Mcfe is primarily due to the commencement of lower cost production in South Texas and North Texas following our December 2012 acquisitions in these areas as well as a lower realized cost on our higher volume East Texas 2013 completions. The following table displays the lease operating expense by area for the years ended December 31, 2013 and 2012:

	For the Year Ended December 31, 2013	Per Mcfe	December 31, 2012	Per Mcfe
	(in thousands, except per Mcfe data)			
South Texas	$ 2,266	$ 0.23	$ 246	$ 0.65
East Texas	36,183	0.86	40,360	0.88
North Texas	6,162	0.52	248	